TransAlta™

TransAlta Corporation

2015 Annual Integrated Report

Letter to Shareholders

This was a year of exceptional external challenges by any measure. We began the year with goals of strengthening our balance sheet to ensure we would maintain solid credit metrics through a low point in the commodity cycle, and moderately growing the company. We foresaw the economy slowing in many of our markets but could never have predicted the dramatic change in the policy framework in Alberta for carbon, the weakening of the Canadian dollar in response to low oil and gas prices, and the significant lack of confidence investors had for investments in the energy and power sectors. We met many of the goals we set for ourselves in 2015, but by the end of the year, these unforeseen events called for substantive and proactive action.

In mid-January 2016, we announced prudent and proactive steps we were taking to support our transition from coal to gas-fired and renewable generation. These steps included a significant reduction to our dividend, suspension of our dividend reinvestment plan, and plans to reposition our capital structure by focusing on raising non-recourse project-level debt to fund debt maturities over the next few years. These decisions will provide us with the full flexibility we need to work with the Government of Alberta on a coal transition plan, re-align the balance sheets of TransAlta and TransAlta Renewables, and prepare for the opportunities that will arise as coal is converted to gas-fired and renewable generation here in Alberta.

We also separated the financial strategies of TransAlta and TransAlta Renewables and prepared the company for new opportunities that will arise as more certainty emerges in the Alberta market. We will have many opportunities for investment as the Alberta market eliminates coal from its generation portfolio by 2030. Our work in the next few years is to ensure that we have a market structure and policy environment that supports investment.

You will also see a difference in our annual reporting this year, as we've consolidated our Annual Report and Report on Sustainability into an Annual Integrated Report for 2015. This is long overdue. We simply cannot act in the power generation space without considering a balanced scorecard that includes economic, operational, safety, people, and environmental goals and results.

Investment Choices

As we move into 2016, TransAlta is a different investment choice for shareholders. Investors who choose TransAlta should be focused on our moderate risk profile given some exposure to merchant risk and Alberta Power Purchase Arrangements (PPAs) that expire in 2020, as well as our ability to leverage our competitive advantages when new growth opportunities arise in the medium to longer term. Investors interested in lower risk and the stability of yield that comes from long-term contracts will be attracted to TransAlta Renewables. TransAlta will maintain a high level of ownership in TransAlta Renewables and will use the cash distributions it receives to support its dividend and take advantage of gas and renewable growth opportunities.

Through 2016, we will continue to face uncertainty over the long-term stability of cash flows generated by our coal plants in Alberta as we work with the government-appointed negotiator on the transition from coal to renewables and gas by 2030. Fortunately, your company has a diversified asset base; Canadian coal accounts for only approximately 25 per cent of our comparable EBITDA net of sustaining capital expenditures, and our current PPAs protect our cash flows until the end of 2020. There is no question in my mind that the negative perception of TransAlta due to the policy environment surrounding coal needs to be resolved so that investors can more easily assess the value of our cash flows.

2015 Performance

We set out in 2015 to achieve world-class safety performance, deliver on our operational and financial goals, pay down $500 million in debt and grow modestly. Anticipating a prolonged period of low commodity prices, we had been on a path since 2014 to reduce overhead costs, simplify our structure and reduce the size of the management team to ensure stronger accountability and decision-making.

In 2015, we exceeded our safety target and achieved our best-ever result in this area. We delivered adjusted fleet availability, which accounts for economic dispatching at U.S. coal, of a respectable 89 per cent. Additionally, we exceeded our guidance for comparable free cash flow and generated comparable funds from operations and comparable EBITDA at the lower end of our guidance ranges, excluding an adjustment to provisions relating mostly to prior years.

During the year, we repaid $500 million of U.S. debt and began 2016 with liquidity of approximately $1.4 billion. We accomplished this by completing two major transactions to drop-down assets to TransAlta Renewables raising almost $400 million in equity, and reducing our interest in TransAlta Renewables by selling an eight per cent share of our TransAlta Renewables ownership to Alberta Investment Management Corporation (AIMCo) for $200 million. That said, our net debt level at the beginning of 2016 is approximately $150 million higher than it was at the beginning of 2015. This increase is attributed to funding the construction of the South Hedland power station in Australia and the acquisition of two renewable projects in 2015. Also impacting our debt was the severe depreciation of the Canadian dollar, although the impact to the company was mitigated by our foreign exchange hedges.

Our cost reduction initiatives led to changes in the operation of the Highvale mine and Canadian Coal and reduced our overhead. Our work was thoughtful and we took the time needed to ensure that the new organization was structured appropriately and our people would have the capabilities to make decisions for the future. As well, various restructuring initiatives across the company reduced the total staff complement by 17 per cent over the prior year, including a 38 per cent reduction in the total size of our management team from 225 to 139 positions. The combination of reduced operating costs, improved operating performance, particularly in Canadian Coal, and our cost reduction initiatives is expected to result in annual cost savings of approximately $50 million.

My last comments on our 2015 successes relate to growth and strategic actions. We continued to advance our position in Australia as we completed the construction of the natural gas pipeline to our Solomon power facility and made great strides in the construction of the South Hedland power station, which will bring new cash flows in mid-2017. We also successfully advanced our contracted asset base. Early in the year we secured a 15-year contract extension, effective December 2016, for our Windsor gas facility, and last fall we reached a strategic agreement with Suncor Energy to extend the existing arrangements at the Poplar Creek cogeneration facility until 2030. As part of this transaction, we extended the contract for our gas-fired assets with Suncor and transferred the ownership of the steam generator to Suncor. The transaction included an agreement to acquire Suncor's interest in two wind facilities, which increased our renewable portfolio in Ontario and Alberta. Our transition to renewables was further enhanced with the acquisition of 71 megawatts of wind and solar assets in late 2015.

The year was not without its setbacks. We lost our dispute on the timing of outages taken in late 2010 and early 2011 with Alberta's Market Surveillance Administrator. Although we maintain that we never deliberately set out to break rules in the Alberta market, we reached a settlement of $56 million, which allows the market, our customers, our employees and our shareholders to move forward. We thank our customers who stayed with us and we continue to work on regaining the trust the company has enjoyed for more than a century. We do not, and never will, take our customers' support for granted. In April, we will publicly release two independent reviews on our compliance and outages practices that we believe will further build trust with all stakeholders.

Our investment grade rating was confirmed by S&P (BBB-), Fitch (BBB-), and DBRS (BBB). However, in December, Moody's reduced our rating to Ba1 from Baa3. This will not have a material impact on our business. The impacts were well within the range of the liquidity we have for the company and we are moving forward with our investment grade ratings from three rating agencies.

Growing TransAlta Renewables

Today, TransAlta owns 64 per cent of TransAlta Renewables and remains committed to its position as the majority shareholder and sponsor. TransAlta Renewables offers investors who want to participate in gas-fired and renewable generation the stability of cash flows associated with highly contracted assets with solid counterparties. The investment thesis is more about stable yield than growth. Today, TransAlta Renewables has a direct or indirect investment in most of our wind assets, our hydro assets outside of Alberta, our gas portfolio in Australia and our Sarnia cogeneration plant in Ontario.

> In mid-January 2016, we announced prudent and proactive steps we were taking to support our transition from coal to gas-fired and renewable generation.

We see the market for contracted gas and renewable assets slowly growing over the next several years. We have additional assets that would be a good fit with TransAlta Renewables and we will continue to grow this entity while maintaining our ownership in the 60 to 80 per cent range. For TransAlta shareholders, the cash distributions from TransAlta Renewables secure the dividend and ensure we have cash to continue strengthening our balance sheet and grow. Further drop-downs to TransAlta Renewables will be designed to grow the value of TransAlta Renewables and raise cash for future growth.

Focusing in 2016 and Beyond

In November 2015, the Government of Alberta announced the Climate Leadership Plan that established several environmental and energy targets for Alberta, including the phase out of emissions from coal-fired generation by 2030 and the addition of a significant carbon price to our business once the coal PPAs roll off. To ensure price stability and reliability, and to avoid unnecessarily stranding capital, the conversion of the strategy to policy will require significant work between industry and government. The government is expected to appoint a negotiator to work with the coal generators on a predictable and phased approach to coal shutdown. The replacement generation will be renewables and natural gas. However, the manner in which it will all come together in the current Alberta market is unclear at this time.

Shareholders are facing unprecedented uncertainty regarding the value of TransAlta's Alberta assets and this is reflected in the current market value of the company. As such, our first priority in 2016 is to reach an agreement with the government on the path forward for coal. Once this is accomplished, we believe we will be able to show how coal will support our final transition to a clean power company. As part of this, we see important work in ensuring that the Alberta electricity market structure supports solid returns for our existing gas-fired and renewable assets and provides the right incentives to attract new investment for our shareholders.

Our second priority is to ensure that our strategy of raising non-recourse debt for our contracted assets is executed; this follows on success in this area in 2015 when we closed a $442 million bond offering secured by the assets of a subsidiary of TransAlta Renewables. This strategy will be employed on an accelerated basis to ensure maximum financial flexibility as opportunities for growth in the gas and renewables sectors arise.

Our additional priorities are as follows:

- Completing construction of South Hedland and bringing the plant to full operation by mid-2017;
- Continuing to focus on building strong, long-term relationships with our customers and partners as we near the end of the PPAs;
- Building options for investment in the Alberta market, including coal-to-gas conversions and greenfield wind, solar, and hydro, and ensuring the gas-fired Sundance unit 7 is shelf-ready for investment should the market change;
- Growing TransAlta Renewables' distributions per share; and
- Creating capital structures for TransAlta and TransAlta Renewables that are consistent with their value propositions.

And, as always, we'll continue to focus on delivering strong operational, safety, financial, people and environmental performance. We've outlined those goals in our report.

Conclusion

Investors desire certainty. We know that, and throughout our work with government we will be reinforcing that message. The Alberta electricity market is complex and haste in implementing the carbon framework could lead to unexpected results and unintended consequences. So, we'll be weighing the pros and cons while taking the time needed to get the framework right and helping investors understand their investment in TransAlta.

I am optimistic about the ability of our team to deliver on our day-to-day and long-term goals. The company is stronger in 2016 due to the actions we've taken over the past three years. The work we completed sets us up for the future. We have time to ensure that changes to Alberta's carbon policy are implemented in a way that meets the objective of competitive pricing and system reliability for our customers while allowing us to generate the returns we need for the remaining life of the coal plants. Our company is equipped with the right people, information and resources to make this equation work, and we are ready to ensure our customers have the right prices and you have the right returns.

Many thanks to our Board of Directors, our management team, and our employees as we've navigated through some difficult external conditions. To those investors who have taken the long view, thank you for your confidence.

Dawn L. Farrell
President and Chief Executive Officer

February 17, 2016

Message from the Chair

A prudent and focused management team and Board must make strategic plans based on available credible information and analysis, while being prepared to use judgment to adjust if facts and events differ substantially from the underlying assumptions; 2015 was such a year for TransAlta.

In 2015, the economy of Alberta, where the majority of our assets are situated, experienced a material and precipitous deterioration due in large part to the decline in oil prices. This reduction in economic activity, among other factors, both dampened demand for electricity and depressed power prices. In that context, the management team at TransAlta designed and executed several initiatives that enabled the company to deliver quality financial, safety, operational and environmental results. As a consequence, TransAlta entered 2016 with a lower cost structure, a more diversified asset base and a refined financial strategy designed to address the market we face, not the one we had hoped for. Among the significant new facts is an evolving provincial carbon policy in Alberta that fundamentally alters the long-term economics associated with our coal-fired generating fleet.

TransAlta is affected in multiple ways by government regulation and policies and the Board regularly reviews the company's compliance policies and practices. As an example, following the regulatory proceeding with Alberta's Market Surveillance Administrator, the Board and management undertook a thorough review of relevant policies and practices and we are confident that the company has in place a rigorous compliance program.

To implement a proactive and solid financial strategy in 2016, the Board decided to revise the dividend, suspend the dividend reinvestment plan going forward in order to stop the dilution of shareholders, and focus on project financing mechanisms as we restructure debt. These steps were necessary, as economic volatility and uncertainty concerning new regulatory policy around our coal fleet requires the strengthening of our balance sheets. Funds previously allocated to dividend payments will be employed to reduce debt and will be reinvested in the company to protect and enhance the investment made by you, our shareholders. This firm financial foundation is critical to the future success of the company in a dynamic environment.

TransAlta will work diligently and in good faith with the Alberta government to realize its pledge not to strand capital unnecessarily, protect consumers and communities, and implement the transition to gas and renewables through 2030, allowing for a reasonable, workable transition timeline. Our coal plants and resulting cash flows are supported for several years by the Alberta Power Purchase Arrangements and long-term contracts, as TransAlta transitions to even more natural gas and renewables assets.

As we address current challenges, we are planning now for the future to provide reliable, sustainable electricity to consumers in Alberta and other markets in which we operate. Among our options are conversion of coal plants to gas, development of new gas-fired plants, enhancement of hydro power, and expansion of wind and solar. As generating capacity is removed from the market in Alberta, a healthy power generating industry is critical to future economic growth. TransAlta has been providing quality and reliable service for over 100 years from our Alberta base, and we look forward to continuing to do so for generations to come.

I can assure you that TransAlta management and your Board are focused on the future to ensure that the interests of our customers, investors and employees are advanced every day. While the developments in 2015 clearly put pressure on our stock, we believe the more efficient, more diversified, more financially stable company we are building will be poised to deliver reliable service to our customers and value to shareholders as we go forward.

Thank you for your support and I look forward to our discussions at our annual meeting.

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chair of the Board of Directors

February 17, 2016

Management's Discussion and Analysis

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*This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2015 consolidated financial statements and our Annual Information Form for the year ended Dec. 31, 2015. 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, 2015. 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 Feb. 17, 2016. 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 2016 Financial Outlook 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 related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2016 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), comparable free cash flow ("FCF"), and expected sustaining capital expenditures for 2016); expectations in respect of financial ratios and 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 2016 and beyond; expected governmental regulatory regimes and legislation (including the Government of Alberta's Climate Leadership Plan) 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 outcome of negotiations with the Government of Alberta in relation to coal-fired generation transition under the Climate Leadership Plan; and 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; 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; including the anticipated financial impact of increased Specified Gas Emitters Regulation ("SGER") obligations in Alberta, and the value of offsets generated by our wind facilities in the province; 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; expectations in respect of our community and environmental initiatives; and expectations in respect of the Keephills Unit 1 Force Majeure event, including the impact of the claim.

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; 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 2016 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, 2015, 2014, and 2013. 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 and Other Measures on a Comparable Basis sections of this MD&A for additional information.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2015	2014	2013
Revenues	2,267	2,623	2,292
Comparable EBITDA(1,2)	945	1,036	1,023
Net earnings (loss) attributable to common shareholders	(24)	141	(71)
Comparable net earnings (loss) attributable to common shareholders(1)	(48)	68	81
Comparable funds from operations(1)	740	762	729
Cash flow from operating activities	432	796	765
Comparable free cash flow(1,2)	315	280	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.09)	0.52	(0.27)
Comparable net earnings (loss) per share(1)	(0.17)	0.25	0.31
Comparable funds from operations per share(1)	2.64	2.79	2.76
Comparable free cash flow per share(1,2)	1.13	1.03	1.09
Dividends declared per common share	0.72	0.72	1.16

As at Dec. 31	2015	2014	2013
Total assets	10,947	9,833	9,624
Total credit facilities, long-term debt, tax equity, and finance lease obligations(3), net of cash	4,441	4,013	4,305
Total long-term liabilities	5,704	4,504	5,337

- Comparable EBITDA decreased by $91 million to $945 million compared to 2014. Excluding a $59 million adjustment to provisions relating mostly to prior years, comparable EBITDA would have been $1,004 million. A significant part of the year-over-year reduction in comparable EBITDA is due to Energy Marketing results during the second quarter of 2015, and lower prices in Alberta and the Pacific Northwest. Energy Marketing delivered strong performance in 2014 because of extraordinary conditions in the Northeast during the first quarter. Prices in Alberta averaged $33 per megawatt hour ("MWh") in 2015 compared $49 per MWh in 2014. Our high level of contracts and hedges mostly mitigated the impact of low prices, but our wind and hydro businesses in Alberta were impacted. Continued improvement in our mining operations to reduce fuel costs mitigated the impacts of lower availability in Canadian Coal during the first half of the year.
- Comparable FFO decreased by $22 million to $740 million. Lower interest expenses and cash taxes offset some of the impact from lower comparable EBITDA. The non-cash adjustment to provisions of $59 million does not impact FFO.
- Comparable net loss attributable to common shareholders was $48 million ($0.17 net loss per share), down from comparable net earnings of $68 million ($0.25 net earnings per share) in 2014. The decrease was primarily due to lower comparable EBITDA and higher earnings attributable to non-controlling interest associated with the sale of additional non-controlling interests in TransAlta Renewables.

(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 and Other Measures 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) 2014 and 2013 restated to deduct hydro life extension capital expenditures from comparable FCF. Refer to the Current Accounting Changes section of this MD&A.
(3) Includes current portion.

- Reported net loss attributable to common shareholders was $24 million ($0.09 net loss per share) compared to net earnings of $141 million ($0.52 net earnings per share) in 2014 and a net loss of $71 million ($0.27 net loss per share) in 2013. Reported net earnings includes the gain on the Poplar Creek contract restructuring ($192 million[1]) and the cost of the settlement with the Market Surveillance Administrator (the "MSA") ($55 million[1]) in 2015. Changes in the fair value of de-designated and economic hedges at U.S. Coal also had a negative impact on our net earnings ($38 million[1,2]) (2014 – $35 million[1,2] positive, 2013 – $67 million[1,2] negative). Deferred income tax expense was also impacted by the increase in the Alberta corporate tax rate in June 2015 and by the sale of an economic interest in our Australian business to TransAlta Renewables, offsetting a reversal of a writedown of deferred tax assets associated with movements in financial instrument values. The loss in 2013 includes a $42 million[1] settlement of a prior year claim relating to power trading activities in California, a $22 million[1] assumption of pension obligations and $19 million[1] associated with the return to service of Sundance 1 and 2.
- During 2015, credit facilities, long-term debt, and finance lease obligations increased by approximately $439 million primarily as a result of the stronger US dollar ($392 million) and the acquisition of operating wind and solar facilities ($211 million). Increases in value resulting from the stronger US dollar were offset by corresponding increases in value of U.S. assets as part of our hedging program. On Jan. 6, 2016, we completed a transaction with TransAlta Renewables to sell economic interests of certain assets located in Canada and received $173 million in cash proceeds as part of the transaction. All proceeds were used to reduce amounts borrowed under our credit facilities.

Highlights

During the year, we continued to work on strengthening our financial condition and flexibility, improve our operating performance, and grow our portfolio of highly contracted assets through the following initiatives:

- We raised over $1.0 billion of capital in 2015, including cash proceeds from sale of an economic interest of certain assets located in Canada to TransAlta Renewables which closed on Jan. 6, 2016, to retire maturing debentures of US$500 million and $155 million. Of the amount raised, over $575 million represents equity raised through the sale of non-controlling interests:
  - On May 7, 2015, TransAlta Renewables acquired an economic interest in our Australian assets (the "Transaction") for total consideration of $1,278 million, comprised of net cash proceeds of $211 million as well as a combination of 58.3 million common shares and 26.1 million Class B shares of TransAlta Renewables.
  - On Nov. 26, 2015, we sold 20.5 million common shares of TransAlta Renewables to the Alberta Investment Management Corporation ("AIMCo"), for net cash proceeds of $193 million.
  - On Jan. 6, 2016, TransAlta Renewables acquired an economic interest based on the cash flows of the Sarnia cogeneration facility and of two renewable energy facilities for proceeds valued at $540 million. Net 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.

  We raised $442 million in long-term non-recourse debt, which is secured by three wind projects in Ontario on Oct. 1, 2015. Project-level debt allows us to align the maturity profile of principal with the realization of value from our assets, which will be the central piece of our financing strategy to repay debentures maturing in 2017 and 2018.
- 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. This year, we extended the contractual profile of three facilities:
  - We restructured our contractual arrangements at the Poplar Creek facility, to extend the contracted cash flows attributable to Poplar Creek from 2023 to 2030, and we also acquired two wind facilities, representing 65 megawatts ("MW") of capacity. As part of the restructuring, our customer acquired our steam generators and the rights to the output of the gas generators and will assume operational control of the site. As a result of the transaction, we recognized a finance lease of $372 million, and increased our long-term assets to reflect the acquisition of two wind farms for $138 million. The transaction closed on Sept. 1, 2015 and we have recognized a gain of $262 million on the transaction. The carrying amount of net assets we transferred to the counterparty was $250 million.
  - We signed a new 15-year 72 MW power supply contract for our Windsor facility with Ontario's Independent Electricity System Operator ("IESO"), taking effect in December 2016.

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(1) Net of related income tax expense.

(2) Hedge accounting could not be applied to certain contracts, and accordingly, the mark-to-market on these contracts impacted reporting 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.

    - We extended the contract for our 55 MW Parkeston power station in Australia by a period of 10 years from November 2016.
- We acquired 71 MW of fully contracted renewable generation assets for cash consideration of $106 million together with the assumption of $105 million of project financing obligations. The assets include our first solar facilities, representing 21 MW of capacity in Massachusetts, and one 50 MW wind farm in Minnesota. The acquisition of the solar facilities was completed on Sept. 1, 2015, while the acquisition of the wind farm closed on Oct. 1, 2015.
- We reached an agreement with the MSA to settle all outstanding proceedings before the Alberta Utilities Commission (the "AUC") for a total amount of $56 million. Of this amount, we paid $31 million in the fourth quarter and $25 million will be paid in the fourth quarter of 2016.
- Overhead reductions and our efficiency and productivity initiatives in Canadian Coal will contribute in excess of $47 million in cost savings annually.
- We received approval from the AUC to construct Sundance 7, an 856 MW high-efficiency natural gas-fired power plant in Alberta. Construction of Sundance 7 will not commence until we have contracted a significant portion of the plant capacity.
- In March, we successfully completed construction of the natural gas pipeline to our Solomon power station. Since then, the pipeline has contributed $10 million to our EBITDA and FFO.
- We continued to advance the construction of the South Hedland power project. Bulk earthworks and civil work were largely completed during the year, and major equipment has been arriving on schedule. We expect the project to be delivered on schedule and on budget in mid-2017.

On Nov. 22, 2015, the Government of Alberta announced the Alberta Climate Leadership Plan (the "Plan"). In respect of the power generation sector, the Plan targets the retirement of coal generation in the Province of Alberta by 2030; replacement of two-thirds of the retiring coal-fired generation with renewable generation (to achieve a 30 per cent share of generation by 2030) and one-third gas generation; and establishment of a new system of greenhouse gas ("GHG") obligations and allowances benchmarked against highly efficient gas-fired generation beginning in 2018, at a price of $30 per tonne. The Government of Alberta has further stated intentions of providing compensation to coal-fired generators as part of its commitment to treat them fairly and not unnecessarily strand capital.

On Jan. 14, 2016, we announced key actions to support our transition from coal to gas-fired and renewable generation in the Province of Alberta and maximize our financial flexibility:
- We have revised our dividend to $0.16 per common share on an annualized basis from $0.72 previously. The reduction will reduce cash required for the dividend to approximately $45 million from approximately $205 million annually. The revised dividend represents a 15 to 18 per cent payout of our estimated 2016 comparable FCF.
- We have suspended our dividend reinvestment plan in order to stop shareholder dilution. We do not currently expect to raise additional equity in 2016 as the incremental cash from the dividend reduction will be used to strengthen our balance sheet and financial flexibility.
- We will focus on raising non-recourse debt to fund upcoming corporate debt maturities. We expect to raise $400 million to $600 million of project-level debt in 2016 to fund the next material debt maturity of US$400 million in 2017, and we plan to execute a similar strategy for the 2018 maturities.
- We will negotiate 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.
- Over the next 15 years, we will focus on replacing coal-fired generation assets with gas-fired and renewable generation assets.

These actions, combined with initiatives completed in 2015, allow us to build the financial capacity and flexibility to address upcoming debt maturities and capitalize on opportunities in gas-fired and renewable generation that will arise as Alberta transitions from coal to clean power.

Segmented Operational Results

Comparable EBITDA and operational performance for the business is as follows:

Year ended Dec. 31	2015	2014	2013
Availability (%)[1]	88.7	89.7	85.5
Adjusted availability (%)[2]	89.0	90.5	87.8
Production (GWh)[1,3]	40,673	45,002	42,482
Comparable EBITDA[4]			
Canadian Coal	334	389	311
U.S. Coal	67	65	67
Gas	330	312	332
Wind and Solar	176	179	181
Hydro	73	87	148
Energy Marketing	37	75	58
Corporate	(72)	(71)	(74)
Total comparable EBITDA	945	1,036	1,023

- Canadian Coal: Comparable EBITDA decreased by $55 million to $334 million in 2015, compared to $389 million in 2014 and $311 million in 2013. The 2015 EBITDA includes a $59 million adjustment to provisions relating mostly to force majeure events for the periods between 2013 to 2015. Excluding this adjustment, 2015 comparable EBITDA would have been $393 million, in line with 2014. Incremental reductions in operating expenses at our Highvale mine offset the negative impact of lower availability on our comparable EBITDA. Our high level of contracts and hedges in Canadian Coal continues to mostly offset the impact of lower prices in Alberta compared to 2014 and 2013. In 2013, the Segment had experienced lower availability.
- U.S. Coal: Comparable EBITDA was consistent with our 2014 and 2013 results as the stronger US dollar offset the impacts of lower pricing in the Pacific Northwest.
- Gas: Comparable EBITDA increased by $18 million to $330 million in 2015 compared to $312 million in 2014 and $332 million in 2013. The increase was a result of additional revenues from the Australian natural gas pipeline and the positive impact of the strengthening of the US dollar on a US-dollar-denominated contract in Australia. The change in value in this contract offsets changes in value of our US-dollar-denominated debt. In 2013, the segment had benefitted from higher Alberta pricing at the Poplar Creek facility and from the last year under a higher-priced contract at the Ottawa plant.
- Wind and Solar: Comparable EBITDA was $176 million in 2015 compared to $179 million in 2014 and $181 million in 2013. The decrease in 2015 is primarily due to lower power prices in Alberta. The acquisition of additional assets in the fourth quarter and the strengthening of the US dollar offset part of this shortfall. In 2014, incremental earnings from the addition of the Wyoming facility had offset the decline in Alberta prices, compared to 2013.
- Hydro: Comparable EBITDA decreased $14 million to $73 million in 2015 compared to $87 million in 2014 and $148 million in 2013, due to the lower prices and a decrease in price volatility in Alberta, which limits our ability to take advantage of our flexibility to produce electricity in higher priced hours.
- Energy Marketing: Comparable EBITDA decreased by $38 million in 2015 to $37 million, compared to $75 million in 2014 and $58 million in 2013. Comparable EBITDA in the first quarter of 2014 included effects of extraordinary market conditions caused by unusual weather in the Northeast. The decrease in 2015 is further due to volatile market conditions in the Alberta and Pacific Northwest regions in the second quarter that negatively affected results.
- Corporate: Our Corporate overhead costs have remained comparable to 2014 and 2013.

(1) Availability and production includes all generating assets (generation operations and finance leases that we operate). 2014 and 2013 availability also includes equity investments, which were sold in May 2014.
(2) Adjusted for economic dispatching at U.S. Coal.
(3) Production includes 314 GWh in 2014 (2013 - 1,556 GWh) from CE Generation LLC and Wailuku Holding Company, LLC, both of which were sold in May 2014.
(4) 2014 and 2013 results restated to reflect the reassignment to the Corporate Segment of $12 million and $7 million, respectively, and to the Energy Marketing Segment of $1 million and $3 million, respectively, of costs associated with certain functions that were determined to benefit the broader organization, or the Energy Marketing Segment, respectively.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO and comparable FCF provide a proxy for the amount of cash generated from operating activities before changes in working capital, and provide the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FFO per share and comparable FCF per share are calculated using the weighted average number of common shares outstanding during the period.

Year ended Dec. 31	2015	2014 *Restated* [1]	2013 *Restated* [1]
Cash flow from operating activities	432	796	765
Change in non-cash operating working capital balances	242	(73)	(74)
Cash flow from operations before changes in working capital	674	723	691
Adjustments			
MSA Settlement payment and impacts associated with California claim	31	33	27
Decrease in finance lease receivable	23	3	1
Payment of restructuring costs	19	-	5
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	(9)	1	5
Other non-comparable items	2	2	-
Comparable FFO	740	762	729
Deduct:			
Sustaining capital	(305)	(361)	(349)
Insurance recoveries of sustaining capital expenditures	25	4	1
Dividends paid on preferred shares	(46)	(41)	(38)
Distributions paid to subsidiaries' non-controlling interests	(99)	(84)	(55)
Comparable FCF	315	280	288
Weighted average number of common shares outstanding in the year	280	273	264
Comparable FFO per share	2.64	2.79	2.76
Comparable FCF per share	1.13	1.03	1.09

(1) Restated to include hydro life extension from growth capital expenditures to sustaining capital expenditures. Refer to the Current Accounting Changes section of this MD&A.

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Year ended Dec. 31	2015	2014	2013
Comparable EBITDA	945	1,036	1,023
Unrealized losses (gains) from risk management activities	1	4	(27)
Interest expense	(230)	(236)	(238)
Provisions	73	-	19
Current income tax expense	(19)	(33)	(39)
Realized foreign exchange gain	17	11	-
Decommissioning and restoration costs settled	(24)	(16)	(24)
Gain on curtailment and amendment of employee future benefit plans	(8)	-	-
Capital insurance recoveries on Canadian Coal facility	(7)	-	-
Flood-related maintenance costs	-	-	5
Other non-cash items	(8)	(4)	10
Comparable FFO	740	762	729

For the year ended Dec. 31, 2015, comparable FFO decreased by $22 million to $740 million compared to 2014 mainly due to the reduction in comparable EBITDA, partly offset by lower interest and cash taxes. Part of the reduction in EBITDA was due to adjustments to provisions, mostly relating to a prior year. The added provision is non-cash and has no impact to our comparable FFO in 2015. Comparable FFO was also positively impacted by the settlement of foreign exchange contracts relating to debt maturities in 2015.

For the year ended Dec. 31, 2014, comparable FFO increased $33 million to $762 million compared to 2013. The increase in FFO outpaced the increase in comparable EBITDA, as the prior year's comparable EBITDA included $27 million of unrealized risk management gains.

Comparable FCF for the year ended Dec. 31, 2015 was $315 million, compared to $280 million in 2014. The increase in comparable FCF was mainly 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, reductions in our gas-fired capital expenditures caused by the Poplar Creek re-contracting and condition-based assessments, and higher insurance recoveries associated with the flood of 2013, partially offset by the reduction in comparable FFO as well as an increase in dividends paid on preferred shares and in distributions paid to non-controlling interests in subsidiaries.

Comparable FCF for the year ended 2014 was $280 million, down $8 million from 2013, as the increase in comparable FFO was offset by distributions paid to TransAlta Renewables' public shareholders and improved performance at TransAlta Cogeneration L.P ("TA Cogen").

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. As shown below, our key financial ratios are currently outside of our target ranges. 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

Year ended Dec. 31	2015	2014	2013
Comparable FFO	740	762	729
Add: Interest on debt net of capitalized interest	223	236	238
Comparable FFO before interest	963	998	967
Interest on debt	232	239	240
Add: 50 per cent of dividends paid on preferred shares	23	21	19
Adjusted interest	255	260	259
Comparable FFO before interest to adjusted interest coverage (times)	3.8	3.8	3.7

Our target for comparable FFO before interest to adjusted interest coverage is four to five times. The ratio is comparable to last year as the cost of funding the South Hedland project is included in our interest expense by adding back capitalized interest to the calculation.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

Year ended Dec. 31	2015	2014	2013
Comparable FFO	740	762	729
Less: 50 per cent of dividends paid on preferred shares	(23)	(21)	(19)
Adjusted comparable FFO	717	741	710
Period-end long-term debt(1)	4,495	4,056	4,347
Add: 50 per cent of issued preferred shares	471	471	391
Less: Cash and cash equivalents	(54)	(43)	(42)
Fair value (asset) liability of hedging instruments on debt(2)	(190)	(96)	(16)
Adjusted net debt	4,722	4,388	4,680
Adjusted comparable FFO to adjusted net debt (%)	15.2	16.9	15.2

Our target for adjusted comparable FFO to adjusted net debt is 20 to 25 per cent. The reduction in the ratio during 2015 is due to lower comparable FFO and the impacts of the strengthening of the US dollar on our US-dollar-denominated debt. Our US-dollar-denominated debt is fully hedged by US-dollar-denominated assets. Net debt includes the increase in value of financial instruments used to hedge approximately half of our US debt. The other half of our US debt is hedged with a US-dollar-denominated financial receivable contract and by our net investment in US operations. The change in value of these assets resulting from the strengthening of the US currency is not included in net debt; the year-over-year change in our US-dollar-denominated net asset amount is $201 million. As at Dec. 31, 2015, net debt is also impacted by the addition of debt resulting from the acquisition of the wind and solar facilities for $211 million. These assets were acquired in September and October and contributed limited FFO in 2015.

(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, 2015 and Dec. 31, 2014.

Adjusted Net Debt to Comparable EBITDA

Year ended Dec. 31	2015	2014	2013
Period-end long-term debt[1]	**4,495**	4,056	4,347
Less: cash and cash equivalents	**(54)**	(43)	(42)
Add: 50 per cent of issued preferred shares	**471**	471	391
Fair value (asset) liability of hedging instruments on debt[2]	**(190)**	(96)	(16)
Adjusted net debt	**4,722**	4,388	4,680
Comparable EBITDA	**945**	1,036	1,023
Adjusted net debt to comparable EBITDA (times)	**5.0**	4.2	4.6

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. During 2015, our ratio deteriorated compared to Dec. 31, 2014, mainly as a result of lower comparable EBITDA during the period and the strengthening of the US dollar.

Sustainability Performance

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.

On a go-forward basis we are integrating our sustainability measures into this MD&A.

2015 Sustainability Targets			
	Financial	Results	Comments
1. Maintain our investment grade rating	Continue to maintain our investment grade credit rating.	Partly achieved	TransAlta maintains investment grade ratings with stable outlooks from three rating agencies: S&P (BBB-), DBRS (BBB), and Fitch (BBB-). On Dec. 17, 2015, Moody's reduced our rating to Ba1.
2. Increase focus on FFO and EBITDA	TransAlta Corporation targets comparable EBITDA and comparable FFO for 2015 in the range of $1,000 million to $1,040 million and $720 million to $770 million respectively.	Partly achieved	For the year ended December 31, 2015, comparable EBITDA was $945 million and comparable FFO was reported at $740 million. Comparable EBITDA includes an adjustment of provisions relating to prior year events in the amount of $59 million.
3. Customers	Grow our offering of products and services to Alberta electricity consumers as the Alberta PPAs expire to match customer power needs with TransAlta's competitive generation.	Achieved	In 2015 we successfully launched a new product to a specific segment of our customer base that offers the customers flexibility and some price certainty without locking them in to a fixed-price, long term agreement.

(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, 2015 and Dec. 31, 2014.

	Power Generating Portfolio	Results	Comments
4. Grow asset portfolio	Grow comparable EBITDA by $40 million to $60 million.	On track	In 2015, TransAlta purchased long-term contracted solar and wind assets expected to add approximately $20 to $25 million of incremental EBITDA in 2016 and commissioned the Fortescue River Gas Pipeline, which is expected to add approximately $10 million of EBITDA on an annualized basis. TransAlta also continues to advance the construction of the South Hedland power project, on budget and on-time. This project is expected to be commissioned in mid-2017 and add approximately $80 million of incremental annualized EBITDA.
5. Achieve top quartile performance within the industry	Continue to deliver 88-90 per cent availability.	Achieved	We achieved adjusted availability in 2015 of 89.0 per cent, compared to 90.5 per cent in 2014, and higher than our target of 88 to 90 per cent. Availability is adjusted for economic dispatching at Centralia.

	Human and Intellectual	Results	Comments
6. Minimize fleet-wide safety incidents	Strive for combined IFR[(1)] below 0.90 in 2015, which is a 10 per cent improvement over the 2014 target.	Achieved	IFR was 0.75, the best ever in our history.
7. Human Resources	a) Maintain a voluntary turnover percentage under 8 per cent in 2015.	Achieved	Turnover was 5 per cent in 2015.
	b) Achieve 100 per cent completion of development plans for all high-potential employees at the top three levels of the organization in 2015.	Partly achieved	88 per cent of our employees have development goals.
	c) Maintain a 100 per cent completion rate on new hire onboarding.	Partly achieved	94 per cent completion rate.
	d) The time to fill vacant position rate remains lower than 60 days for recruiting.	Achieved	54 days was the average to fill vacant positions.

(1) Injury Frequency Rate ("IFR") is defined as the number of lost-time and medical injuries for every 200,000 hours worked.

	Environmental	Results	Comments
8. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 18 in 2015, which is a 10 per cent improvement over the 2014 target.	Achieved	12 recorded incidents in 2015.
9. Mine reclamation	Maintain annual topsoil replacement rate at Highvale Mine of 74 acres/year.	Partly achieved	Replaced topsoil on 65 acres in 2015 due to warm conditions during winter.
10. Maximize by-product revenue opportunities	a) Recycle a minimum of two million tonnes of coal by-product materials during the period 2015 to 2017.	On track	Recycled approximately 700,000 tonnes of coal by-products (fly ash, cenosphere, bottom ash, and gypsum) in 2015.
	b) Recycle 2,000 tonnes of scrap metal materials in 2015.	Partly achieved	Recycled close to 1,000 tonnes.
11. Promoting biodiversity	Install bird and bat habitat improvements at Alberta wind facilities in 2015.	Achieved	• Ferruginous hawk nest platform was installed at Soderglen in March. • 16 bluebird nest boxes were installed at Soderglen in April. • Bat houses were installed at the Pincher Creek and Fort Macleod yards in December.
12. Air emissions management	a) 95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030.	On track	We are on track to achieve this target in 2030.
	b) 20 per cent reduction from 2005 levels by 2021, or the equivalent of 7,000,000 tonnes, of CO_2e per year.	On track	We are on track to achieve this target in 2021.
	c) 55 per cent reduction from 2005 levels by 2030, or the equivalent of 19,700,000 tonnes, of CO_2e per year.	On track	We are on track to achieve this target in 2030.
13. Water Management	a) Enter into a permanent agreement with the Government of Alberta to manage water on the Bow River to aid in potential flood mitigation in 2016.	On track	On track. The Alberta government is still modelling potential solutions and we are waiting for its information to proceed.
	b) Complete third party assurance of TransAlta water consumption and discharge in 2015.	Achieved	We completed a successful third party assurance of water consumption data and processes with Ernst&Young in 2015.
14. Environmental Management Systems (EMS)	Successfully self-audit each wind operations site against the Operations Environmental Management Plans created in 2014.	On track	All sites except for our Quebec and New Brunswick wind farms were audited. We have made good progress in this area. In 2015 a challenging economic climate forced us to implement a travel freeze, which stalled progress on our eastern Canadian sites as travel is required.

	Local Communities	Results	Comments
15. Stakeholder Engagement	The TransAlta Stakeholder Engagement Framework ("SHEF") implementation plan will be finalized in the first half of 2015, which will be followed by the completion of short-term SHEF actions such as internal stakeholder mapping. Full implementation of the SHEF will be completed in 2016.	Achieved	SHEF was finalized in 2015 and high level internal stakeholder mapping exercise was completed.
16. Community Involvement	Increase by 2 per cent the number of company-sponsored volunteering opportunities in 2015.	Not achieved	In 2014, employees volunteered approximately 3,400 hours; in 2015 the total was below 2,500 hours. Company restructuring in 2015 reduced the pool of potential volunteers and expectations were adjusted accordingly.
17. Aboriginal Relations	In 2015 TransAlta will increase the quantity and quality of engagement with First Nation communities by improving internal systems that will allow for feedback and tracking of engagement activities. By 2017, TransAlta is targeting to achieve gold-level designation in the Canadian Council for Aboriginal Bussiness's Progressive Aboriginal Relations certification program.	Achieved	Created tracking forms for all engagement, which helped to ensure TransAlta meets both community and regulatory commitments.

	Comprehensive	Results	Comments
18. Reporting	Achieve year-over-year improvement in the Carbon Disclosure Project ("CDP") by scoring a 90 or greater in 2015.	Achieved	TransAlta scored 100 in 2015 and was added to the CDP Climate Disclosure Leadership Index (representing the top 20 performing companies in Canada)
19. Supply Chain Management (SCM)	In 2015, make available sustainability clauses for optional inclusion into standard TransAlta request for proposal template and terms and conditions for supplier agreements.	Achieved	Increased focus on suppliers to meet sustainability standards

Business Model and Competitive Forces

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 of gross generating capacity and use a broad range of generation fuels comprised of coal, natural gas, water, sun, and wind. 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, utilizing our expertise, scale, and diversified fuel mix to capitalize on opportunities in our core markets and growing in areas where our competitive advantage can be employed.

Our values are grounded in accountability, integrity, sustainability, safety, and people which 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 four 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 growth of cash flows over the long term. The transition from coal to gas and renewables provides significant opportunity for growth in the future. In 2013, we launched TransAlta Renewables, our sponsored vehicle to own contracted gas and renewable assets.

Regional Competitive Environments

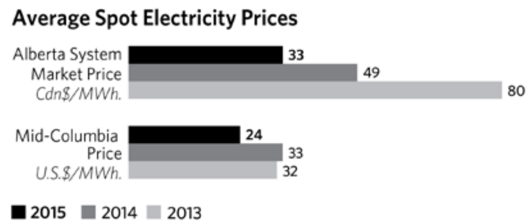
Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity, whereas system capacity, natural gas prices, GHG pricing, government subsidies, and renewable resource availability are key drivers to the supply. Growth in mining investment is key to developing our Australian business.

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 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 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 increased by less than one per cent in 2015 compared to 2014. Concurrently over 2014 and 2015, approximately 1,200 MW of gas generation capacity and approximately 350 MW of wind capacity were added to the market, resulting in a large decrease in power prices, impacting mostly 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 11 per cent. After expiry of the PPAs in 2021, our share of offer control is forecast to increase to approximately 23 to 25 per cent depending on load growth in the province and excluding Sundance 7.

Alberta's Climate Leadership Plan, recently announced by the provincial government, 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.

The government is appointing a negotiator to ensure that the 14-year transition away from coal does not spike power prices, impact system reliability, or unnecessarily strand capital. We will be better able to assess the impact of legislation on the Alberta market after these negotiations are finalized in the 2016 and 2017 timeframe.

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.

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 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.

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.

TransAlta's Capitals

The following discusses TransAlta's main categories of capital, being Financial, Power Generating Portfolio, Human and Intellectual, and Environmental and Local Communities.

Financial Capital

Sources of Capital

Our goal over the last 18 months 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 over $800 million, including a reduction of over $500 million on our credit facility and a $300 million reduction in Canadian and US bonds. Over the next three years, we plan to continue on this path by replacing $1.2 billion of maturing recourse debt with non-recourse debt secured by certain projects.

On Dec. 17, 2015, Moody's lowered the rating of our senior unsecured debt to Ba1 with a stable outlook. As expected, the direct financial impact of this downgrade has been limited. We have posted additional collateral of nearly $100 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. These costs have been integrated into our 2016 financial outlook. We have investment grade ratings with stable outlooks from each of DBRS, S&P, and Fitch Ratings. 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, 2015, our senior unsecured debt is rated as investment grade by three rating agencies: BBB (stable), BBB- (stable), and BBB- (stable) by DBRS, Standard and Poor's ("S&P"), and Fitch Ratings ("Fitch"), respectively, and Ba1 (stable) by Moody's Investors Services ("Moody's"). Our preferred shares are rated P-3 and Pfd-3 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 its judgment, circumstances so warrant. See the Liquidity Risk section of this MD&A.

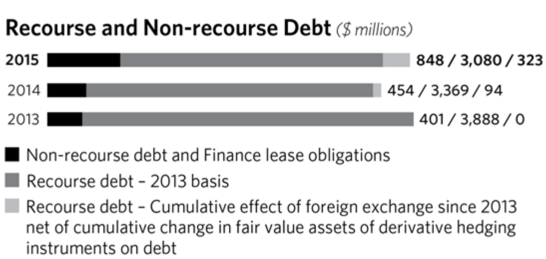
Capital Structure

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

As at Dec. 31	2015 $	2015 %	2014 $	2014 %	2013 $	2013 %
Net debt						
Recourse debt - CAD debentures	1,044	12	1,043	13	1,269	17
Recourse debt - U.S. senior notes	2,221	26	2,444	31	1,797	23
Net credit facilities and other[1]	138	2	(24)	-	822	11
Total recourse debt	3,403	40	3,463	44	3,888	51
Non-recourse debt	766	9	380	5	376	5
Finance lease obligations	82	1	74	1	25	-
Total net debt	4,251	50	3,917	50	4,289	56
Non-controlling interests	1,029	12	594	8	517	6
Equity attributable to shareholders						
Common shares	3,075	35	2,999	38	2,913	38
Preferred shares	942	11	942	12	781	10
Contributed surplus, deficit, and Accumulated Other Comprehensive Loss	(656)	(8)	(657)	(8)	(788)	(10)
Total capital	8,641	100	7,795	100	7,712	100

During 2014 and 2015, we have reduced our corporate senior debt and the amount drawn on our credit facility, primarily through the sale of non-controlling interests, issuance of project-level debt, divestiture of our equity investments, and the issuance of preferred shares. The strengthening US dollar added approximately $325 million to our recourse debt over the two-year period, net of the gain in fair value assets of the derivative hedging instruments on debt. Part of our US-dollar-denominated debt is also hedged using a US-dollar-denominated financial receivable contract and by our net investment in U.S. operations. During 2015, we also added $211 million of debt as part of the acquisition of the two renewable projects in the U.S.

The following graph shows the evolution of recourse debt, including credit facilities and tax equity obligations, versus non-recourse debt, including finance lease obligations, as well as the cumulative effect of foreign exchange:



(1) Includes cash, tax equity financing, and fair value assets of hedging instruments on debt.

Over the last two years, the changes in our US-dollar-denominated debt were offset as follows:

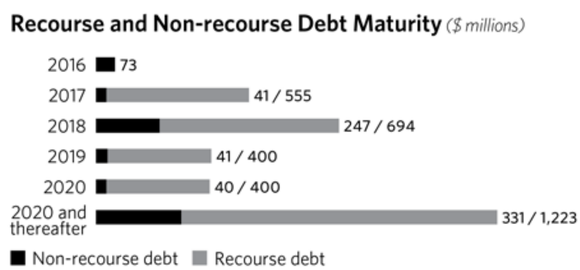
For the year ended Dec. 31	2015	2014
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	201	84
Foreign currency cash flow hedges on debt	183	79
Economic hedges and other	8	11
Total	392	174

On Jan. 15, 2015, our US$500 million 4.75 per cent senior notes matured. On Sept. 1, 2015, $120 million in 5.33 per cent non-recourse debentures matured. These amounts and were paid out using existing liquidity.

On Oct. 1, 2015, a subsidiary of TransAlta Renewables closed a $442 million bond offering, which is secured by a first-ranking charge over the subsidiary's wind farms. 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. Net proceeds of the financing were used to reduce our balance on the credit facility. 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.

The following graph shows our debt maturity schedule as at Dec. 31, 2015, excluding credit facilities, finance lease obligations, and other debt.

Over the next three years, we have approximately $1.6 billion of recourse and non-recourse debt maturing. We will refinance some of these upcoming debt maturities by raising debt secured by some of our contracted assets in Canada and the U.S. We are also expecting to continue our de-leveraging strategy and most of our free cash flow over the next three years, after funding of the South Hedland project, will be allocated to debt reduction.



Our credit facilities provide us with significant liquidity. At Dec. 31, 2015, we had a total of $2.2 billion (2014 - $2.1 billion) of committed credit facilities, of which $1.3 billion (2014 - $1.6 billion) was not drawn. We are in compliance with the terms of the credit facility and all undrawn amounts are fully available. At Dec. 31, 2015, the $0.9 billion (2014 - $0.5 billion) of credit utilized under these facilities was comprised of actual drawings of $0.3 billion (2014 - $0.1 billion) and letters of credit of $0.6 billion (2014 - $0.4 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility expiring in 2019, and four bilateral credit facilities expiring in 2017. We anticipate renewing these facilities, based on reasonable commercial terms, prior to their maturities.

Working Capital

Including the current portion of long-term debt, the excess of current assets over current liabilities was $311 million as at Dec. 31, 2015 (2014 - $472 million - excess of current liabilities over current assets). The primary change relates to the timing of the classification of long-term debt as current. Excluding the current portion of long-term debt, the excess of current assets over current liabilities as at Dec. 31, 2015, was $383 million (2014 - $266 million). The increase is primarily due to the assumption of a new finance lease receivable resulting from the Poplar Creek restructuring ($48 million), and timing of payments and accruals.

Share Capital

On Feb. 17, 2016, we had 287.9 million common shares outstanding, and 12.0 million Series A, 11.0 million Series C, 9.0 million Series E, and 6.6 million Series G preferred shares outstanding. Preferred shares support our financial position as only half of their balance is generally considered as debt by credit rating agencies.

The following tables outline the common and preferred shares issued and outstanding:

As at Dec. 31	2015	2014
	Number of shares *(millions)*	Number of shares *(millions)*
Common shares issued and outstanding, end of year	**284.0**	275.0
Preferred shares		
Series A	12.0	12.0
Series C	11.0	11.0
Series E	9.0	9.0
Series G	6.6	6.6
Preferred shares issued and outstanding, end of year	**38.6**	38.6

Non-Controlling Interests

As of Dec. 31, 2015, we own 66.6 per cent (2014 - 70.3 per cent) of TransAlta Renewables. TransAlta Renewables is a publicly traded company listed on the Toronto Stock Exchange under the symbol "RNW". We also own 50.01 per cent of TA Cogen, which owns, operates, or has an interest in four natural gas-fired facilities and one coal-fired generating facility. 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.

TransAlta Renewables has been the cornerstone of our funding strategy over the last three years, starting with its formation with some of TransAlta's wind and hydro assets in mid-2013. TransAlta Renewables forms 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. During 2015, we initiated two transactions with TransAlta Renewables with concurrent public equity offerings by TransAlta Renewables:

- 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 the recently commissioned 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 $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.
- On Jan. 6, 2016, we completed the sale of an economic interest of 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. After completing this transaction, we own 64 per cent of TransAlta Renewables.

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.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2015	2014	2013
Interest on debt	228	238	240
Capitalized interest	(9)	(3)	(2)
Interest on finance lease obligations	4	1	-
Other	7	-	-
Accretion of provisions	21	18	18
Net interest expense	251	254	256

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 strengthening of the US dollar and other interest expense associated with the adjustment to provisions have partially offset these decreases.

In 2014, net interest expense decreased compared to 2013, primarily due to the approximate $500 million reduction in debt during the year and lower interest rates on debt that was refinanced. Higher interest expense due to strengthening of the US dollar had partially offset these decreases.

Dividends to Shareholders
During the year ended Dec. 31, 2015, 9.0 million (2014 - 6.8 million) common shares were issued to shareholders that elected dividend reinvestment, for a total of $76 million (2014 - $85 million).

On Jan. 14, 2016, we announced the resizing of our common share dividend from $0.72 annually to $0.16 annually and the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan effective immediately. These actions were taken as part of a plan to maximize our long-term financial flexibility. Declaration of dividends is at the discretion of the board of directors of TransAlta (the "Board").

On Feb. 16, 2016, we declared a quarterly dividend of $0.04 per share on common shares, payable on April 1, 2016 and a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2016.

Non-Controlling Interests
Comparable earnings attributable to non-controlling interests for the year ended Dec. 31, 2015 increased $31 million to $80 million compared to 2014, primarily due to the additional common shares issued to the public in relation to the Australia portfolio dropdown in addition to higher earnings of TransAlta Renewables on a larger asset base.

In 2014, comparable earnings attributable to non-controlling interests increased $20 million compared to 2013, primarily due to the formation of TransAlta Renewables and increased public ownership.

Collectively, the two transactions effected in 2015 and early 2016 have allowed TransAlta Renewables to increase its dividend by approximately 14 per cent over 2015, with a further six to seven percent increase expected upon commissioning of the South Hedland project. This corresponds to an average annual increase of approximately six per cent between the 2013 Initial Public Offering to mid-2017. Through our majority ownership of TransAlta Renewables, we are the primary beneficiary of these increases.

Ability to Deliver Financial Results
The metrics we are using 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		2015	2014	2013
Comparable EBITDA	Target	**1,000 to 1,040**	1,015 to 1,065	Not applicable
	Actual	**945**	1,036	1,023
Comparable FFO	Target	**720 to 770**	743 to 793	800 to 900
	Actual	**740**	762	729
Comparable FCF(1)	Target	**265 to 270**	274 to 324	Not applicable
	Actual	**315**	280	288

The adjustment to the provision recognized at Dec. 31, 2015, mostly related to prior year events, caused the departure from the guidance. Before this adjustment was made, comparable EBITDA in 2015 was trending to the low end of the range, as a result of much lower prices in Alberta and the Pacific Northwest impacting our merchant generation. Our commodity risk management strategy is designed to protect us from short-term price variations. However, it is challenging to efficiently hedge our Alberta wind portfolio. Although our hydro portfolio is substantially all contracted, the Alberta hydro PPA allows us to benefit from price volatility in a low price and volatile price environment; however, we were not able to capture the value of this flexibility.

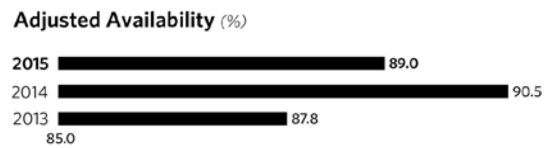
(1) 2014 and 2013 restated to deduct hydro life extension capital expenditures from comparable FCF. Refer to the Current Accounting Changes section of this MD&A. Target range boundaries for 2014 have been adjusted by an amount equal to the change in reported amount.

Power Generating Portfolio

Our power generating portfolio is comprised of our fleet of power generating and related assets as well as our finance leases. We monitor availability closely as a key metric to delivering the required production to meet our contractual obligations and achieve financial targets. Over the short term and medium term, we adjust our maintenance and sustaining capital expenditures to optimize financial returns on our investments. We benchmark our performance against peers with the objective to rank within the first quartile. Over the long term, we adjust our growth capital expenditures to align with our strategic orientations.

Availability and Production

Our adjusted availability target was 89 to 91 per cent for 2015.



Our availability in 2015, after adjusting for economic dispatching at U.S. Coal, was 89.0 per cent (2014 - 90.5 per cent; 2013 - 87.8 per cent). Lower availability for the year ended Dec. 31, 2015 compared to last year was due to higher unplanned outages and derates at Canadian Coal. 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 PPA to the PPA buyer and the Balancing Pool of a "High Impact Low Probability" force majeure event. In the event of a force majeure event, we are entitled to continue to receive our PPA capacity payment and are exempted, under the terms of the PPA, from having to pay availability penalties. We expect the counterparty to the PPA to disagree with our determination that the event qualifies as a force majeure and we recorded a provision to reflect a potential outcome. The costs incurred as a result of the event was mostly covered by insurance. Consequently, the outage did not have a material financial impact on our results in 2015.

Production for the year ended Dec. 31, 2015 decreased 4,329 gigawatt hours ("GWh") compared to 2014, primarily due to lower availability at our Canadian Coal plants, and increased periods of lower prices in the Pacific Northwest where it was more economical to supply our contractual obligation by buying power in the market. Additionally, the Poplar Creek restructuring deal resulted in lower production, as the facility is now outside our operational scope.

Production for the year ended Dec. 31, 2014 increased 2,520 GWh compared to 2013, primarily due to a full year of contribution from Sundance Units 1 and 2, which returned to service in the second half of 2013, as well as the return to service of Keephills Unit 1, which was unavailable for seven months in 2013.

Operational

We continuously drive for the cost-effective operation of our facilities. In 2015, we announced the elimination of positions to reduce our costs. This company-wide initiative is expected to result in annual cost savings in excess of $47 million annually.

In the generation segments, our operations, maintenance, and administration ("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 reflects the cost of day-to-day operations. The following table outlines our generation comparable OM&A over the last three years:

	2015	2014	2013
Generation comparable OM&A	418	433	417

Our goal is to reduce our OM&A through cost control and targeted productivity initiatives. We have established long-term service agreements with third-party suppliers to reduce these costs, as well as maintenance-related sustaining capital costs. We regularly benchmark our performance against peers to measure our progress. OM&A costs decreased in 2015 due to changes in operational scope in the Gas segment, with the benefits of the cost-saving initiatives beginning to be realized. During 2013, OM&A costs were lower due to Sundance Units 1 and 2 returning to service late in the year.

In Canadian Coal, costs associated with our Highvale mine form part of our cost of fuel. In addition to the impact of the reduction in the number of positions, we have driven reductions in coal costs through improved mine design sequence, reduced equipment requirements, and optimized contractor usage. Since insourcing the activity in 2013, coal costs per tonne have decreased by 15 per cent, from approximately $27 to $23.

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 is recoverable from third parties.

Year ended Dec. 31	2015	2014 *Restated* (1)	2013 *Restated* (1)
Routine capital	101	135	133
Mine capital	25	45	53
Planned major maintenance	162	162	153
Finance leases	13	10	9
	301	352	348
Flood-recovery capital	4	9	1
Total sustaining capital expenditures	305	361	349
Insurance recoveries of sustaining capital expenditures	(25)	(4)	(1)
Net amount	280	357	348

Lost production as a result of planned major maintenance is as follows:

Year ended Dec. 31	2015	2014	2013
GWh lost (2)	1,409	1,519	1,154

(1) Restated to include hydro life extension from growth capital expenditures to sustaining capital expenditures. Refer to the Current Accounting Changes section of this MD&A.

(2) Lost production excludes periods of planned major maintenance at U.S. Coal, which occur during periods of economic dispatching.

In 2015, routine capital decreased due to the transfer of our Poplar creek facility and condition-based assessments at our Ontario gas-fired generating stations. Routine capital also included additional expenditures on capital spares and the Keephills ash solutions project in 2014. The mine capital expenditure was lower in 2015 as 2014 included significant expenditure on development activities of a new mining area. Finance lease costs increased primarily due to the strengthening of the US dollar in 2015. Planned major maintenance costs remained stable in 2015 compared to 2014 as scope changes offset the improvement in efficiency of our major turnaround costs in Canadian Coal. On Nov. 14, 2014, we entered into an agreement with Alstom to provide major maintenance for our Canadian Coal facilities. The agreement relates to 10 major maintenance projects over the subsequent three years at our Keephills and Sundance plants. It also expands Alstom's current scope of work to service critical power assets, including boilers, steam turbines, generators, and other plant equipment. Alstom will be accountable for providing its services on budget and on time with a guarantee on performance. Excluding the effects of scope changes to our Sundance 3 outage this year, the new arrangement is on track to deliver an average 15 per cent cost reduction per turnaround and shorter turnaround times for major maintenance work, resulting in estimated direct cost savings of $34 million over the full term of the agreement. Other planned major outages in 2015 included Sundance 5, Keephills 3, and one outage at Sheerness.

The decrease in mine capital in 2014 compared to 2013 was primarily due to fewer mine support equipment purchases as mining intensity stabilized. Planned major maintenance costs in 2014 included five planned outages at Sundance Unit 5, Sundance Unit 6, Keephills Unit 2, U.S. Coal, and Genesee Unit 3 in 2014 compared to four in 2013 at Sundance 4, Keephills 3, U.S. Coal, and Sheerness.

Growth

We have set out to grow comparable EBITDA by $40 to $60 million annually. Our target investments are focused on highly contracted gas and renewable power generation.

During 2015 we have acquired the following renewable generation facilities:

- On July 26, 2015, we agreed to acquire 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. The purchase of the solar projects in Massachusetts closed on Sept. 1, 2015 and the purchase of the Lakeswind wind project in Minnesota was completed on Oct. 1, 2015.
- As part of the arrangement to restructure our Poplar Creek contract, on Sept. 1, 2015, we acquired the 20 MW Kent Breeze wind facility located in Ontario and a 51 per cent interest in the 88 MW Wintering Hills wind facility located in Alberta. The Kent Breeze facility has a 20-year contract with the Ontario IESO.

These assets further supplement our pipeline of potential assets for dropdown into TransAlta Renewables, as part of our financing strategy.

Previously announced growth projects have progressed in line with expectations:

- On March 19, 2015, we completed the Fortescue River Gas Pipeline in Western Australia. The project, our first pipeline, was completed within a nine-month timeframe and for an estimated total cost of AUD$183 million. We hold a 43 per cent interest in the pipeline. The pipeline delivers gas to our Solomon power station, which services Fortescue Metals Group's mining operations at the Solomon Hub.
- Construction of the 150 MW gas-fired South Hedland project commenced in January 2015. The civil construction phase is progressing with all major foundation footings complete, with the exception of the steam turbine. Manufacturing and factory acceptance testing of primary electrical equipment was completed. Major equipment was received on site. Installation and testing of the main underground fuel gas pipeline was completed. Integration of the existing balance-of-plant control systems within the overall station control system and associated plant operation, monitoring, and communication requirements is progressing well.

These initiatives will add approximately $35 million in EBITDA in 2016 and an additional $80 million annually when the South Hedland project will be in service during the second quarter of 2017.

Our target investments are focused on highly contracted gas and renewable power generation:

- contracted assets support our financial position, as we transition to having increased merchant capacity in Alberta in the next decade; and
- gas and renewable generation is our core orientation towards reducing our impact on the environment and utilizes our expertise in wind, hydro, and gas.

All investments are subject to due diligence procedures and ultimately reviewed by our investment committee (refer to the Governance and Risk Management section of this MD&A).

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 past year, 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 in five years, along with an option to buy back into this project or into other projects of TAMA Power during this period.

Contractual Profile

Approximately 65 per cent of our capacity is sold under long-term contract. Excluding Alberta PPAs for our coal and hydro facilities, the majority of these contracts have maturities in excess of 10 years. Amongst these groups of facilities, significant new contracts have been extended in respect of the Poplar Creek, Windsor, and Parkeston facilities, the details of which are provided below.

With most of our coal and hydro facilities in Alberta rolling off the Alberta PPA in 2021, our focus has been to develop a portfolio of commercial and industrial customers to sell our generation in the province post PPA. We are now serving a portfolio of 600 MW.

Poplar Creek

On Sept. 1, 2015, we closed the restructuring of our contractual arrangement for power generation services with Suncor Energy ("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, which has a maximum capability of 376 MW, 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 will provide 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 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 wind facility located in Alberta. The Kent Breeze facility has a 20-year contract with the Ontario IESO.

The transaction creates value by increasing the duration of the contract to 2030 from the prior 2023 expiry, reduces our exposure to Alberta's merchant power market, and adds two high quality wind facilities representing 65 MW of capacity. The addition of a fully contracted gas generating asset and two wind farms supplements our pipeline of assets that we could sell to TransAlta Renewables in the future. As a result of the transaction, we recognized a finance lease of $372 million and increased our long-term assets to reflect the acquisition of two wind farms for $138 million. The transaction closed on Sept. 1, 2015 and we have recognized a gain of $262 million on the transaction. The carrying amount of net assets we transferred to the counterparty in the transaction was $250 million.

Windsor

During the first quarter of 2015, we executed a new 15-year power supply contract with Ontario's IESO for our Windsor facility, which will be 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 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 agreement remain consistent with the original contract. 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 and Intellectual Capital

As at Dec. 31, 2015, we had 2,380 active employees. This number has decreased by 17 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 54 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.

Safety

Safety is our top priority with all of our staff, contractors, and visitors. Injury Frequency Rate ("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. We achieved our best results ever for safety performance in 2015, exceeding our IFR target of 0.90. We have experienced no fatalities during the last three years.

Year ended Dec. 31	**2015**	2014	2013
IFR	**0.75**	0.86	0.93

During 2015, we designed a new total safety management policy as a two-pronged approach. The policy builds upon 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 keeping all hazards inside our equipment, through definition and measurement of safety-critical performance measures and operating limits.

Employee Benefits

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 include 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 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 $65 million to secure the obligations under the supplemental plan.

Organizational Culture and Structure

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. We are currently focused on training employees to adapt to these changes.

Fleet Management

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.

Our energy trading and marketing operations optimize the financial returns of our facilities in real time. The group purchases fuels to feed plants, bids into energy markets the electricity we generate at our facilities, 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 margins ranging from approximately $60 million to $80 million annually and EBITDA of $40 million to $60 million annually. 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 had no impact on our internal control over financial reporting at Dec. 31, 2015. As a result of the implementation of the ETRMS, certain processes supporting our internal control over financial reporting are expected to change in 2016. Management will continue to monitor these processes going forward.

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. A key resolution achieved during 2015 was the confirmation by the Alberta Electric System Operator that Sundance Units 3 to 6 comply with reactive power standards. Additionally, we set aside annually $10 million to $15 million to invest in productivity projects and further the innovation from our employees. Productivity projects are evaluated against criteria that include a two- to three- year financial payback. During 2015, we completed some boiler erosion mitigation projects on Sundance 5. These improvements to the shielding and support attachments in the boiler are designed to reduce boiler tube leaks and reliability.

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 implementation 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 plan to finalize developing the balance of safety-critical maintenance strategies and related engineering standards. We have observed positive increases in self-reporting and addressing process safety hazards as awareness and new tools are being introduced.

New or Emerging Technologies

We seek to maintain TransAlta in pace with power technologies that have the potential to re-define power markets today and in the future. In certain markets, renewables penetration is rapidly changing the economic position of incumbent generators. As demonstrated by our investments in wind in the past decade, we are intent on adapting our business model to these changing realities. During 2015, we made our first investment in solar technology with the purchase of the Massachusetts solar facilities. We are also beginning to experiment with battery storage technology.

Environmental and Local Communities 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 coal and 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.

In the jurisdictions in which we operate, legislators have proposed and enacted regulations to discontinue over time the use of the technologies that 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 we therefore 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 three years, we have added approximately 350 MW in renewable energy capacity. Of these additions, 45 MW of capacity generates offsets that can be used against GHG emissions in Alberta.
- 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. 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 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 announced environmental rules that have not yet entered into effect, such as Clean Air Strategic Alliance ("CASA") rules in Alberta (as detailed in the following Regional Regulation and Compliance sub-section), we investigate the cost effectiveness of multiple technological solutions and various operating models in order to prepare appropriate work scopes.
- 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 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. As at Dec. 31, 2015, 67 of the facilities that we own and our mines have EMS based on the globally recognized ISO 14001 EMS Standard.

We recorded 12 environmental incidents in 2015 (2014 - 15 incidents), which is lower than our target of 18 (2014 - 20). One of these incidents led to an environmental enforcement action, for which fines were nominal.

Similarly, the volume of spills has been limited, with 19 m^3 spilled, of which 99 per cent was recovered (2014 – 463 m^3, 96 per cent recovered). This year marked a record year for the low volume of spills and is a testament to our increased focus and scrutiny placed on reporting all spills in order to understand their causes and take action to mitigate further incidents.

Air Emissions

In 2015, we estimate that 32.2 million tonnes of GHGs with an intensity of 0.87 tonnes per MWh (2014 - 35.1 million tonnes of GHGs with an intensity of 0.89 tonnes per MWh) were emitted as a result of normal operating activities[(1)]. Our GHG emissions decreased in 2015, primarily as a result of lower production from coal plants. Variations in other air emissions (NOx, SO_2, particulate matter, and mercury) trended similarly to GHG emissions.

Other decreases in emissions of the 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. Our continued investment in growth from renewable power generation further supports the decrease in emissions intensity observed in 2015.

We believe in proactive measurement and disclosure of air emissions. In 2015, TransAlta was the only power generation company recognized as part of the Top 20 in Canada in the Climate Leadership Index.

Resource utilization

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 ranges of 220-240 m^3 of water across our fleet. 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 we operate. The difference between withdraw and discharge, representing consumption, is largely due to evaporative loss.

Our areas of higher water risk are situated east of Perth in our single-cycle gas plants in Western Australia and in our Southern Alberta hydro operations. We continue to maintain ample water at all sites that require water for operation.

In Southern Alberta, following the flood of 2013, our hydro facilities are being solicited for an increased water management role than they have played in the past. During 2015, we established an interim agreement with the Government of Alberta to use our Ghost hydro reservoir for potential flood mitigation purposes. As part of the agreement, we lowered the reservoir level below typical operating levels for a longer period, and received compensation for commercial opportunity costs. We continue to engage with the government and partners towards a comprehensive water management framework that involves flood and drought mitigation.

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(1) 2015 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 Greenhouse Gas 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.

Land

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-establishment of drainage, replacement of 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 2015, we reclaimed 65 acres (26 hectares) at our Higvale mine, slightly 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 variance has been accounted for and incorporated into the mine's go-forward reclamation plans.

During 2015, we obtained approvals for our Highvale mine to develop a new area, which we anticipate will be the final area required to support our Sundance and Keephills facilities through to the end of their operation in 2030.

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 of 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. During 2015, our revenue from by-product sales amounted to $28 million (2014 – $31 million). The decrease is primarily attributable to the lower production.

Regional Regulation and Compliance

Environmental issues and related legislation have, and will continue to have, an impact upon 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 environmental 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 environmental requirements, as well as changes in our liabilities under these requirements, which may have a material adverse effect upon our consolidated financial results.

Alberta

On Nov. 22, 2015, the Government of Alberta announced its Climate Leadership Plan. That Plan established several environmental and energy targets for Alberta, including:

- the phase-out of emissions from coal-fired generation by 2030;
- the replacement of two-thirds of the retiring coal-fired generation with renewable generation and one-third with gas generation;
- the objective of achieving up to 30 per cent of Alberta's electricity production from renewables by 2030; and
- maintaining reliability, reasonable prices to customers and businesses, and ensuring capital is not unnecessarily stranded.

The Province of Alberta will develop its associated regulations as well as a compensation plan for coal units in 2016. We will negotiate 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.

On Sept. 11, 2012, the Canadian federal government published the final regulations governing GHG emissions from coal-fired power plants. The regulations provide for up to 50 years of life for coal units, at which point units must meet an emissions performance standard of approximately 420 tonnes per GWh. There are some exceptions that require older units commissioned before 1975 to reach end of life by Dec. 31, 2019, and units commissioned between 1975 and 1986 to reach end of life by Dec. 31, 2029.

We believe the regulations provide additional operating time and increased flexibility for our Canadian Coal units, allowing those units to comply in a more cost-effective manner. Our Keephills 3, Genesee 3, and Sheerness facilities, however, would be subject to the shorter 2030 limit proposed by the Alberta government.

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 SGER:

- 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 they 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 CASA. The release of the federal regulations creates a potential misalignment between the CASA air pollutant requirements and schedules, and the GHG retirement schedules for older coal plants, which in themselves will result in significant reductions of NOx, SO_2, and particulates.

We are in discussions with the provincial government in an effort to ensure coordination between GHG and air pollutant regulations, such that emission reduction objectives are achieved in the most effective manner while taking into consideration the reliability and cost of Alberta's generation supply.

Pacific Northwest

On Aug. 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 (tons) 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: 2022 to 2029, and 2030 and beyond.

On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the State, 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.

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 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 April 13, 2015, the Ontario government announced that Ontario will be implementing a GHG cap-and-trade system in an effort to reduce emissions and fight climate change. The cap-and-trade system will impose a hard ceiling on the GHG emissions allowed in each sector of the economy. The details of the cap-and-trade system (such as specifics on a potential cap, covered sectors, or anticipated launch date) have not been determined but are to be developed through stakeholder consultations. Our contracts at Gas facilities in the province generally include provisions protecting us from adverse changes in laws.

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 capacity to be installed to add to the slightly more than 4,000 MW already operating. Since the Australian assets are fully contracted it is not expected that these amendments will have a significant impact.

Climate Change

Abnormal weather events that are sometimes associated with climate change can impact our operations and give rise to risks. Among other events, 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 into substantial repair work. Our losses have been largely covered through insurance; and
- 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.

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 which benefitted our energy marketing group.

Local Communities

We provide public benefit through reliable, cost-efficient power and related outputs or services. In the face of declining social acceptability of coal and with its phase-out on the horizon, we seek to secure favourable outcomes for our workers and the communities surrounding our plants. The approach is summarized in CEO Dawn Farrell's editorial on TransAlta's Dial Down - Dial Up submission to the Government of Alberta. "We are prepared to invest hundreds of millions of dollars to dial up the transition to new renewables, including hydro, wind, and solar. Dial Down - Dial Up starts with an agreement with the province, environmental groups, the communities in which we operate, and our employees, because jobs matter. Not jobs that will be created in the future, but thousands of jobs held today by our employees and contractors. That's almost 3,000 people, not including jobs in the communities where they work. And electricity prices matter, because there is a real risk to consumers, including Alberta businesses, of price spikes and volatility." TransAlta advocated for a sufficiently long timelines for transition, support for facility redevelopment, funds for retraining, and economic diversification. Our successful agreement with the State of Washington, in 2011, and our proposal in Alberta leading up to the Climate Leadership Plan illustrate this approach.

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 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 agreement, we will pay a total amount of $56 million that includes approximately $27 million as a repayment of economic benefit, approximately $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million has been paid in the fourth quarter, and the $25 million administrative penalty will be paid in the fourth quarter of 2016. As a result of the approval, we have discontinued our appeal of the AUC's decision.

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 have undertaken two independent, third-party reviews of our current compliance procedures around forced outages, and of our trading compliance program, the results of which will be made public. We have received findings from these independent reports, including some recommendations for improvement, and are finalizing our response to the reports and recommendations.

Public Health

We seek to maintain public health and safety by restricting physical access to our operating sites and ongoing monitoring of air emissions from our coal and gas plants.

During the year, public assertions have been made concerning the impact of coal plants on air quality in the Edmonton area. In order to verify the veracity of this information, we funded an independent analysis of the sources of air quality issues in and around the Edmonton area by University of Alberta scientist Dr. Warren Kindzierski, using provincial government monitoring data from the past nine years.

Dr. Kindzierski's work has determined that emissions from coal-fired generation are in fact a minor contributor to Edmonton's air pollution. Chemical "signatures" for emissions pointed to several sources, including local industries, vehicles, and wood-burning fireplaces in relation to air quality concerns in Edmonton. Only about 10 per cent or less of all particulate matter in the airshed can be attributed to coal combustion emissions.

The study also looked at 17 years of wind patterns and confirmed that, in most seasons, the local winds around Edmonton predominantly blow into the city from the south and southeast, not from the west where coal-fired generation is concentrated.

Stakeholder Engagement

TransAlta is implementing a corporate stakeholder engagement framework, a streamlined corporate-wide approach to ensure that engagement and relationship-building practices are consistent across TransAlta's locations and types of work. Our aboriginal relations group continues to develop and enhance aboriginal relations programming in areas of employment, economic development, community engagement, and investment to position TransAlta for achieving top standing in 2017. Since 2014, we have achieved the Canadian Council for Aboriginal Business' silver-level Progressive Aboriginal Relations certification, and we are targeting to achieve gold-level by 2017.

Community

During 2015, TransAlta contributed $3.5 million in donations and sponsorships (2014 - $3.6 million).

On July 30, 2015 we announced that we are 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.

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.

Discussion of Segmented Comparable Results

During the first quarter of 2015 we began reporting Canadian Coal, U.S. Coal, Gas, Wind, and Hydro as separate business segments. Previously, these were collectively reported as the Generation Segment and were further differentiated by fuel type within our MD&A to provide additional information to our readers. The change in segmentation under IFRS has minimal impact on our MD&A. No changes arose in respect of our Energy Marketing and Corporate segments. See the Current Accounting Changes section of this MD&A for additional information.

Solar facilities acquired in September 2015 have been included in our Wind and Solar Segment as it is integrated to this business from a management perspective.

Comparable figures are not defined under IFRS. Refer to the Earnings and Other Measures on a Comparable Basis section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Canadian Coal

Year ended Dec. 31	2015	2014	2013
Availability (%)	84.3	88.6	80.9
Contract production (GWh)	20,256	21,748	17,789
Merchant production (GWh)	3,827	3,806	3,779
Total production (GWh)	24,083	25,554	21,568
Gross installed capacity (MW)	3,786	3,771	3,771
Revenues	912	1,023	916
Fuel and purchased power	379	436	393
Comparable gross margin	533	587	523
Operations, maintenance, and administration	194	196	203
Taxes, other than income taxes	12	12	11
Gain on sale of assets	-	(1)	(2)
Net other operating income	(7)	(9)	-
Comparable EBITDA	334	389	311
Depreciation and amortization	299	292	292
Comparable operating income	35	97	19
Sustaining capital:			
Routine capital	48	56	69
Mine capital	25	45	65
Finance leases	10	10	9
Planned major maintenance	107	100	94
Total sustaining capital expenditures	190	211	237
Insurance recoveries of sustaining capital expenditures	(7)	-	-
Net amount	183	211	237

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 the year (Sundance 4, and Keephills 1 Force Majeure 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 found. Generation was also reduced due to economic dispatch resulting from the current low price environment.

Comparable EBITDA in 2015 was $334 million compared to $389 million in 2014. 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 last year. 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 to the Keephills 1 Force Majeure outage and additional work at Sundance 3.

Depreciation and amortization for the year ended Dec. 31, 2015 increased by $7 million compared to 2014 due to the addition of assets at our Highvale mine.

For the year ended Dec. 31, 2015, sustaining capital expenditures decreased by $21 million compared to 2014. In 2014, we incurred additional cost for the development of a new mining area, and the acquisition and refurbishment of vehicles as part of our mining operations.

2014

Production for the year ended Dec. 31, 2014 increased 3,986 GWh compared to 2013. Production for 2013 was impacted by a seven-month outage at our Keephills 1 facility and the return to service of Sundance 1 and 2 in September and October, respectively.

For the year ended Dec. 31, 2014, comparable gross margin increased by $64 million compared to 2013, primarily as a result of lower unplanned outages, lower unit coal costs, and contract price escalations. Lower prices in Alberta in 2014 compared to 2013 decreased incentive payments received for generation in excess of PPA targets, offsetting some of the gain in reliability. We were able to achieve the reduction in coal costs after we took over operations at the Highvale mine in 2013.

OM&A for the year ended Dec. 31, 2014 decreased despite much higher operating capacity with Sundance Units 1 and 2 returning to service. We achieved a reduction in OM&A as a result of reduced maintenance costs associated with lower unplanned outages and the implementation of initiatives to reduce costs.

Other operating income resulted from the settlement of a dispute with a supplier in relation to an equipment failure in prior years.

Depreciation and amortization for the year ended Dec. 31, 2014 was consistent compared to 2013. The increase in depreciation and amortization relative to 2013 resulted from an increased asset base, primarily related to Sundance Units 1 and 2 returning to service, was offset by fewer asset retirements during the year and the life extension of certain components.

For the year ended Dec. 31, 2014, sustaining capital decreased $26 million compared to 2013 as a result of the Keephills 1 Force Majeure outage in 2013 and investments required to increase mining intensity.

U.S. Coal

Year ended Dec. 31	2015	2014	2013
Availability (%)	**87.4**	82.8	78.3
Adjusted availability (%)[1]	**89.5**	87.7	91.9
Contract sales volume (GWh)	**2,868**	1,131	996
Merchant sales volume (GWh)	**5,484**	6,102	6,459
Purchased power (GWh)	**(3,329)**	(549)	(744)
Total production (GWh)	**5,023**	6,684	6,711
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues	**431**	368	346
Fuel and purchased power	**311**	251	227
Comparable gross margin	**120**	117	119
Operations, maintenance, and administration	**50**	49	48
Taxes, other than income taxes	**3**	3	4
Comparable EBITDA	**67**	65	67
Depreciation and amortization	**63**	54	56
Comparable operating income	**4**	11	11
Sustaining capital:			
Routine capital	**2**	2	6
Finance leases	**3**	-	-
Planned major maintenance	**10**	10	10
Total	**15**	12	16

2015

Production decreased 1,661 GWh in 2015 compared to 2014, as a result of a reduction in our generation to supply our contractual obligation by buying cheaper power in the market.

In December 2014, we commenced 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 will escalate again by 100 MW in December 2016. We can also re-supply the contract by buying power from the market when economical to do so and further improve our margin. Because of this option for financial settlement, it is accounted 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 was offset by the impacts of lower prices on our merchant sales.

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.

(1) Adjusted for economic dispatching.

2014

Production was stable in 2014 compared to 2013, as higher unplanned outages at U.S. Coal were offset by lower economic dispatching as certain months during the period had higher prices that made production more economic.

Comparable EBITDA decreased $4 million in 2014, as 2013 comparable EBITDA included the favourable effects of adjustments to commercial arrangements recognized in prior periods. The effect of prior year adjustments was partially offset by increased optimization margins earned, as we were able to capitalize on high market volatility early in the year.

For the year ended Dec. 31, 2014, sustaining capital decreased by $4 million compared to 2013 primarily due to reduced general equipment repair and replacement.

Gas

Year ended Dec. 31	2015	2014	2013
Availability (%)	94.7	94.0	94.5
Contract production (GWh)	5,078	5,363	5,892
Merchant production (GWh)	1,535	2,027	1,962
Total Production (GWh)	6,613	7,390	7,854
Gross installed capacity (MW)(1)	1,405	1,531	1,779
Revenues	650	744	683
Fuel and purchased power	229	326	252
Comparable gross margin	421	418	431
Operations, maintenance, and administration	88	102	97
Taxes, other than income taxes	3	4	3
Net other operating income	-	-	(1)
Comparable EBITDA	330	312	332
Depreciation and amortization	118	114	108
Comparable operating income	212	198	224

Sustaining capital:			
Routine capital	8	24	17
Planned major maintenance	23	39	41
Total	31	63	58

(1) *Includes production capacity for Fort Saskatchewan and Solomon power stations, which have been accounted for as finance leases. During the quarter, operational control of our Poplar Creek facility was transferred to 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 from Sept. 1, 2015, the date of transfer of operational accountability. Refer to TransAlta's Capitals section of this MD&A for further information. Assets of the Centralia gas plant were sold in the fourth quarter of 2014 and the production capacity was removed from our gross capacity measures at that time.*

2015

Production for the year ended Dec. 31, 2015 decreased 777 GWh compared to 2014, predominantly due to the transfer of operational control of the Poplar Creek facility to our customer, effective Sept. 1, 2015.

Most of our contracts provide for pass-through of fuel cost to the counterparty limiting our exposure to fuel price. 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 last year, 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 last year. The Poplar Creek restructuring transaction had a minimal impact on EBITDA compared to last year as a lower gross margin was offset by lower operating costs. The increase in comparable EBITDA is 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 the year.

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, as well as impacts from the Poplar Creek restructuring deal, and higher asset retirements. These were partially offset through the extension of certain asset lives.

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.

2014

Production for the year ended Dec. 31, 2014 decreased 464 GWh compared to 2013 due to the reduced requirement to run our Ottawa facility under the terms of its new capacity-based contract. The new contract is consistent with our contracting strategy and its 20-year duration supports continued investment in the facility.

Comparable EBITDA for the year ended Dec. 31, 2014 decreased by $18 million compared to 2013, primarily due to the impact of lower Alberta prices on our merchant capacity in Poplar Creek and the reduced contribution from our Ottawa facility under the terms of the new contract. These decreases in comparable EBITDA were partially offset by the benefits achieved through resale of higher priced excess gas during unplanned outages in 2014. The 2014 results include an $8 million unrealized loss on forward purchase and physical gas volumes in Ontario, which is offset by unrealized gains of the same amount in the Energy Marketing Segment.

For the year ended Dec. 31, 2014, sustaining capital increased by $5 million compared to 2013 mainly due to compressor repairs at Mississauga.

Wind and Solar

Year ended Dec. 31	2015	2014	2013
Availability (%)	95.8	94.6	93.8
Contract production (GWh)	2,146	2,228	1,700
Merchant production (GWh)	1,060	947	1,009
Total production (GWh)	3,206	3,175	2,709
Gross installed capacity (MW)[1]	1,424	1,291	1,289
Revenues	250	247	237
Fuel and purchased power	19	14	13
Comparable gross margin	231	233	224
Operations, maintenance, and administration	48	48	38
Taxes, other than income taxes	7	6	5
Comparable EBITDA	176	179	181
Depreciation and amortization	99	88	79
Comparable operating income	77	91	102

Sustaining capital:			
Routine capital	1	2	3
Planned major maintenance	12	10	6
Total	13	12	9

2015

Production for 2015 increased slightly by 31 GWh compared to 2014, primarily due to better wind resources and availability in Western Canada, and contribution from three additional wind farms and our first solar facility acquired during the second half of the year (111 GWh). This was partially offset by lower wind resources at Wyoming after 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 positively impacting our U.S. assets.

Depreciation and amortization for 2015 increased by $11 million compared to 2014 primarily due to the additions of new projects during the year.

Sustaining capital for the year ended Dec. 31, 2015 was comparable to 2014.

2014

Production for the year ended Dec. 31, 2014 increased 466 GWh compared to 2013, primarily due to the contribution from a full year of operations at Wyoming and New Richmond and higher wind volumes in Eastern Canada.

For the year ended Dec. 31, 2014, comparable EBITDA decreased by $3 million compared to 2013. Lower prices in Alberta in 2014 compared to 2013 more than offset the contribution of new wind projects commissioned or acquired in 2013.

Depreciation and amortization for the year ended Dec. 31, 2014 increased by $9 million compared to 2013, primarily due to the higher asset base associated with recently added facilities.

For the year ended Dec. 31, 2014, sustaining capital increased by $3 million compared to 2013 mainly due to an increase in planned major maintenance activities as a result of an outage at Le Nordais.

(1) *Includes production capacity for the recent Solar and Wind acquisitions.*

Hydro

Year ended Dec. 31	2015	2014	2013
Contract Production (GWh)	1,662	1,810	2,022
Merchant production (GWh)	86	75	72
Total production (GWh)	1,748	1,885	2,094
Gross installed capacity (MW)	926	913	913
Revenues	116	131	181
Fuel and purchased power	8	9	5
Comparable gross margin	108	122	176
Operations, maintenance, and administration	38	38	31
Taxes, other than income taxes	3	3	3
Net other operating income	(6)	(6)	(6)
Comparable EBITDA	73	87	148
Depreciation and amortization	25	24	25
Comparable operating income	48	63	123

Sustaining capital(1)**:**			
Routine capital, excluding hydro life extension	3	9	8
Hydro life extension	18	19	8
Planned major maintenance	10	3	5
Total before flood-recovery capital	31	31	21
Flood-recovery capital	4	9	1
Total sustaining capital expenditures	35	40	22
Insurance recoveries of sustaining capital expenditures	(18)	(4)	(1)
Net amount	17	36	21

2015

Production for 2015 decreased by 137 GWh compared to 2014 as a result of lower water resource.

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 floods.

Sustaining capital expenditures 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. We expect to spend $15 to $20 million to complete the flood recovery.

2014

Production for the year ended Dec. 31, 2014 decreased 200 GWh compared to 2013 due to lower water resource in Western Canada and optimization of storage capacity to capture highest prices.

Comparable EBITDA decreased by $61 million in 2014 compared to 2013, primarily as a result of lower prices and low price volatility in Alberta, which limited our ability to take advantage of our flexibility to produce electricity during higher priced hours.

(1) 2014 and 2013 restated to include hydro life extension from growth capital expenditures to sustaining capital expenditures. Refer to the Current Accounting Changes section of this MD&A.

Net other operating income relates to business interruption insurance proceeds received in respect of prior period events.

For the year ended Dec. 31, 2014, total sustaining capital increased by $18 million compared to 2013, mainly due to higher spending on hydro life extension projects and flood-recovery capital related to the Alberta flood of 2013. The flood-related expenditures were mostly recovered through insurance proceeds recognized in net earnings in 2014, as non-comparable items.

Equity Investments

We completed the sale of our interests in CE Generation LLC ("CE Gen") and CalEnergy, LLC ("CalEnergy") in June 2014 and Wailuku River Hydroelectric, L.P. ("Wailuku") in November 2014.

The equity method was used to account for the results of the CE Gen, CalEnergy, and Wailuku joint ventures for the months of January and February 2014, but ceased effective March 1, 2014. There were no earnings from Equity Investments during the two-month period in 2014 (2013 annual - loss of $10 million).

Energy Marketing

Year ended Dec. 31	2015	2014	2013
Revenues and comparable gross margin	49	108	79
Operations, maintenance, and administration	12	33	21
Comparable EBITDA	37	75	58
Depreciation and amortization	1	-	1
Comparable operating income	36	75	57

Comparable EBITDA from Energy Marketing totalled $37 million, approximately half of last year's contribution, due to a return to normal performance from trading activities in the Northeast after extraordinary market conditions in the first quarter of 2014 and the negative impact from unexpected volatile markets in Alberta and the Pacific Northwest during the second quarter of 2015. Performance during the second half of the year was largely in line with last year. Lower OM&A costs partially offset the shortfall in revenue as a significant portion of our costs is incentive compensation that is impacted by lower margins generated by the business.

Corporate

The expenses incurred by the Corporate Segment are as follows:

Year ended Dec. 31	2015	2014	2013
Operations, maintenance, and administration and taxes other than income taxes	72	71	74
Depreciation and amortization	25	26	23
Comparable operating loss	97	97	97
Sustaining capital:			
Routine capital	21	23	22

Our Corporate overhead costs have remained comparable to 2014 and 2013, and we anticipate to begin realizing benefits of our overhead reductions during 2016.

Routine capital expenditures for the year ended Dec. 31, 2015 decreased compared to 2014, mainly as a result of a reduction in corporate information technology costs.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

Alberta Merchant Cash Generating Unit

As part of the annual impairment review and assessment process in 2013, the Corporation's Alberta plants with significant merchant capacity were considered one cash-generating unit (the "Alberta Merchant CGU"). While no impairment losses were recognized in 2013 for the Alberta Merchant CGU, total pre-tax impairment losses of $23 million that were recognized previously in the Wind Segment plants that became part of the Alberta Merchant CGU were reversed. Please refer to Note 6 of our audited consolidated financial statements within our Annual Report for additional information.

The Alberta Merchant CGU's recoverable amount was based on an estimate of fair value less costs of disposal using a discounted cash flow methodology based on our long-range forecasts and prices evidenced in the marketplace. Due to a substantial excess of fair value over net book value at other plants included within the Alberta Merchant CGU, valuation assumptions and methodologies were not a significant driver of the impairment reversals.

We consider the relationship between our market capitalization and our book value, among other factors, when reviewing for indicators of impairment. The slowdown in the oil and gas sector has put Alberta into a recession, and put 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. As at Dec. 31, 2015, our market capitalization was below our book value of equity. The government has stated intentions of providing compensation to coal-fired generators as part of its commitment to treat them fairly and not unnecessarily strand capital. We intend to negotiate an arrangement with the government.

As part of our monitoring controls, we estimate a recoverable amount for each Cash Generating Unit ("CGU") by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on our 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. These estimates are used to assess the significance of potential indicators of impairment and provide a criterion to evaluate adverse changes in operations.

During the fourth quarter, we completed a sensitivity analysis on these estimates 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 analysis 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 our large renewable fleet in the province.

U.S. Coal

As at Nov. 30, 2014, we 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. We estimated the fair value less costs of disposal of the CGU, utilizing our long-range forecast, and the following key assumptions:

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

The valuation is subject to measurement uncertainty based on those assumptions, and on inputs to 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 our operating activities and capital plan.

We also considered possible impairment at the U.S. Coal CGU in 2015 utilizing a similar process and again found that the fair value less costs to sell approximates the current carrying amount. Accordingly, there were no impairment charges made during the year ended Dec. 31, 2015.

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.

Income Taxes

A reconciliation of income taxes and effective tax rates on earnings, excluding non-comparable items, is presented below:

Year ended Dec. 31	2015	2014	2013
Earnings (loss) before income taxes	221	239	(12)
Comparable adjustments:			
Equity loss	-	-	10
Impacts associated with certain de-designated and economic hedges	60	(54)	103
Asset impairment charges (reversals)	(2)	(6)	(18)
Restructuring expense (recovery)	22	-	(3)
Gain on sale of assets	(262)	(2)	(12)
Economic hedges of non-controlling interest in intercompany foreign exchange contracts	8	-	-
Foreign exchange loss on California claim	-	4	-
Flood-related maintenance costs, net of insurance recovery	(9)	1	7
TAMA Transmission bid costs	-	5	-
Net other operating losses	38	1	109
Comparable earnings before tax	76	188	184
Comparable (earnings) attributable to non-controlling interests before tax	(85)	(53)	(31)
Comparable earnings attributable to TransAlta shareholders subject to tax	(9)	135	153
Comparable income tax expense adjustments:			
Income tax (expense) recovery related to impacts associated with certain de-designated and economic hedges	22	(19)	36
Income tax expense related to asset impairment charges and reversals	(1)	(1)	(5)
Income tax (expense) recovery related to restructuring provision	5	-	(1)
Income tax (expense) recovery related to gain on sale of assets	(70)	1	(2)
Income tax recovery related to divestiture of investment	-	35	-
Income tax (expense) recovery related to writedown of deferred income tax assets	56	5	(28)
Income tax expense related to investment in subsidiary	(95)	-	-
Income tax (expense) recovery related to changes in corporate income tax rates	(20)	-	5
Income tax recovery related to non-comparable items attributable to economic hedges of non-controlling interest in intercompany foreign exchange contracts	2	1	-
Income tax recovery related to flood-related maintenance costs, net of insurance recovery	(2)	-	2
Income tax recovery related to TAMA Transmission bid costs	-	1	-
Income tax recovery related to net other operating losses	(4)	-	27
Total comparable income tax expense adjustments	(107)	23	34
Income tax expense (recovery)	105	7	(8)
Comparable income tax expense (recovery)	(2)	30	26
Comparable income tax expense attributable to non-controlling interest	(5)	(4)	(2)
Comparable income tax expense (recovery) attributable to TransAlta shareholders	(7)	26	24
Comparable effective tax rate on earnings attributable to TransAlta shareholders (%)	78	19	16

The comparable income tax expense attributable to TransAlta shareholders decreased for the year ended Dec. 31, 2015 compared to 2014 due to lower comparable earnings.

In 2014, the comparable income tax expense increased compared to 2013 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned, offset by lower comparable earnings.

The comparable effective tax rate on earnings attributable to TransAlta shareholders increased for the year ended Dec. 31, 2015 compared to 2014 due to certain amounts that do not fluctuate with earnings, and changes in the amount of earnings between the jurisdictions in which pre-tax income is earned.

In 2014, the comparable effective tax rate on earnings attributable to TransAlta shareholders increased compared to 2013 due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

During the year ended Dec. 31, 2015, we reversed a previous writedown of deferred income tax assets of $56 million. The deferred income tax assets relate mainly to the tax benefits of losses associated with our directly owned U.S. operations. We had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from our directly owned U.S. operations to utilize the underlying tax losses, due to reduced price growth expectations. Recognized other comprehensive income during the year ended Dec. 31, 2015 has given rise to a taxable temporary difference that forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

In order to give effect to the Transaction with TransAlta Renewables, a reorganization of certain TransAlta companies was completed. The reorganization resulted in the recognition in 2015 of $95 million deferred tax liability on TransAlta's investment in a subsidiary. The deferred tax liability had not been recognized previously, since prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

During the second quarter of 2015, the Government of Alberta enacted legislation to increase its provincial corporate income tax rate to 12 per cent from 10 per cent, effective July 1, 2015. This resulted in a net increase in our deferred income tax liability of $18 million, of which $20 million is recorded in the Consolidated Statement of Earnings with an offsetting $2 million deferred tax recovery recorded in the Statement of Other Comprehensive Income.

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2015 to Dec. 31, 2014:

	Increase/ (decrease)	Primary factors explaining change
Trade and other receivables	117	Timing of customer receipts and increases in collateral paid and short term portion of finance lease receivables following the Poplar Creek contract restructuring
Inventory	23	Increase in coal inventory following lower production, Mass Solar SREC inventory, and purchase of emission credits
Finance lease receivables (long-term)	372	Poplar Creek contract restructuring
Property, plant, and equipment, net	60	Acquisition of wind and solar assets ($217 million), sustaining capital and construction of the South Hedland project ($493 million) and favourable changes in foreign exchange rates ($139 million), partially offset by the net effect of the Poplar Creek contract restructuring ($130 million), depreciation for the period ($545 million), and revisions to decommissioning and restoration costs ($86 million)
Intangible assets	38	Acquisition of Kent Breeze wind farm
Deferred income tax assets	26	Effect of the internal reorganization associated with the Transaction and an increase in deductible temporary differences
Risk management assets (current and long-term)	420	Gains on commodity and foreign currency cash flow hedges
Other assets	35	Reclassification of Washington State community investment contribution funded but not yet disbursed
Other	23	
Total increase in assets	**1,114**	
Accounts payable and accrued liabilities	(147)	Timing of payments and accruals
Credit facilities, long-term debt, and finance lease obligations (including current portion)	439	Unfavourable effects of changes in foreign exchange rates ($392 million) and increase in non-recourse obligations associated with acquisition of solar and wind facilities ($105 million) and financing of equity to acquire project ($106 million), partially offset by debt repayments ($758 million)
Decommissioning and other provisions (current and long-term)	42	Final installment of MSA settlement ($25 million) and adjustment to provisions ($66 million)
Deferred income tax liabilities	213	Effect of the internal reorganization associated with the Transaction, an increase in the Alberta corporate tax rate, and an increase in taxable temporary differences
Risk management liabilities (current and long-term)	47	Price movements and changes in underlying positions and settlements
Equity attributable to shareholders	77	Gains on cash flow hedges and gains on translating net assets of foreign operations recognized in other comprehensive income, and issuance of common shares, partially offset by the net loss, dividends declared in the period and sale of investment in subsidiaries to TransAlta Renewables
Non-controlling interests	435	Sale of investment in subsidiaries to TransAlta Renewables and net earnings for the period, partially offset by distributions paid and payable to non-controlling interests
Other	8	
Total increase in liabilities and equity	**1,114**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for year ended Dec. 31, 2015 compared to the year ended Dec. 31, 2014:

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	

Year ended Dec. 31	2014	2013	Explanation of change
Cash and cash equivalents, beginning of year	42	27	
Provided by (used in):			
Operating activities	796	765	Increase in cash earnings of $32 million. Refer to our discussion of funds from operations
Investing activities	(292)	(703)	Increase in proceeds on sale of investments of $224 million, a decrease in cash paid on the acquisition of Wyoming Wind of $109 million, a decrease in additions to property, plant, and equipment ("PP&E") and intangibles of $72 million, and a decrease in investing non-cash working capital balances of $31 million, partially offset by a decrease in realized gains on financial instruments of $16 million and a decrease in proceeds on disposal of PP&E of $8 million
Financing activities	(503)	(47)	An increase in repayments of borrowings under credit facilities and in repayments (net of issuances) of long-term debt of $504 million, a decrease in proceeds on sale of non-controlling interest in a subsidiary of $78 million, an increase in distributions paid to subsidiaries' non-controlling interests of $29 million, and an increase in common share cash dividends of $24 million, partially offset by an increase in proceeds on issuance of preferred shares of $161 million and an increase in realized gains on financial instruments of $20 million
Cash and cash equivalents, end of year	43	42	

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, 2015, we provided letters of credit totalling $575 million (2014 - $396 million) and cash collateral of $74 million (2014 - $25 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:

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Natural gas, transportation, and other purchase contracts	52	17	15	6	6	105	**201**
Transmission	14	8	9	7	7	6	**51**
Coal supply and mining agreements	151	46	50	50	52	542	**891**
Long-term service agreements	103	110	23	19	36	70	**361**
Non-cancellable operating leases	9	8	7	7	7	50	**88**
Long-term debt(1)	72	604	947	761	447	1,596	**4,427**
Finance lease obligations	15	14	12	8	7	26	**82**
Interest on long-term debt and finance lease obligations(2)	225	216	171	138	106	796	**1,652**
Growth	85	186	6	1	-	-	**278**
TransAlta Energy Bill	6	6	6	6	6	19	**49**
Total	**732**	**1,215**	**1,246**	**1,003**	**674**	**3,210**	**8,080**

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.

(1) Repayments of long-term debt include amounts related to our credit facilities that are currently scheduled to mature in 2019.
(2) Interest on long-term debt is based on debt currently in place with no assumption as to re-financing an instrument on maturity.

Earnings and Other Measures on a Comparable Basis

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.

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

In calculating these items, we exclude certain items as management believes these transactions are not representative of our business operations. Earnings on a comparable basis per share are calculated using the weighted average common shares outstanding during the period.

During 2015, prior period restatements were made to 2014 and 2013. Refer to the Current Accounting Changes section of this MD&A for a description of these items.

The adjustments made to calculate comparable EBITDA and comparable earnings for the year ended Dec. 31, 2015 and 2014 are as follows. References are to the reconciliation presented on the following pages.

Year ended Dec. 31			2015	2014	2013
Reference number	Adjustment	Segment			
Reclassifications:					
1	Finance lease income used as a proxy for operating revenue	Gas	58	49	46
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Gas	23	3	1
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	62	56	58
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Canadian Coal	-	1	2
Adjustments (increasing (decreasing) earnings to arrive at comparable results):					
5	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	60	(54)	103
6	Restructuring expense (recovery)	Canadian Coal	11	-	(2)
		U.S. Coal	1	-	-
		Gas	1	-	-
		Energy Marketing	3	-	-
		Corporate	6	-	(1)
7	MSA settlement	Energy Marketing	56	-	-
8	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	8	-	-
9	Gain on Poplar Creek contract restructuring	Gas	(262)	-	-
10	Net tax effect on comparable adjustments subject to tax	Unassigned	48	18	(62)
11	(Reversal) accrual of writedown of deferred income tax assets	Unassigned	(56)	(5)	28
12	Income tax expense related to the Transaction	Unassigned	95	-	-
13	Deferred income tax rate adjustment	Unassigned	20	-	-
14	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	(9)	1	7
15	Costs related to TAMA Transmission bid	Corporate	-	5	-
16	Asset impairment charges (reversals)	Gas	(2)	(6)	1
		Wind	-	-	(23)
		Hydro	-	-	4
17	California claim	Energy Marketing	-	5	56
18	Non-comparable portion of insurance recovery received	Hydro	(18)	(4)	(1)
19	Sundance Units 1 and 2 return to service	Canadian Coal	-	-	25
20	Loss on assumption of pension obligation	Canadian Coal	-	-	29
21	Foreign exchange on California claim	Unassigned	-	4	-
22	Non-comparable gain on sale of assets	Equity Investments	-	(2)	-
		Corporate	-	-	(12)
23	Income tax recovery related to sale of investment	Unassigned	-	(36)	-
24	Non-comparable items attributable to non-controlling interest	Unassigned	14	1	-

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2015 and 2014 is as follows:

Year ended Dec. 31	2015				2014			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,267	81 [1, 2]	60 [5]	2,408	2,623	52 [1, 2]	(54) [5]	2,621
Fuel and purchased power	1,008	(62) [3]	-	946	1,092	(56) [3]	-	1,036
Gross margin	1,259	143	60	1,462	1,531	108	(54)	1,585
Operations, maintenance, and administration	492	-	9 [14]	501	542	-	(6) [14, 15]	536
Asset impairment reversals	(2)	-	2 [16]	-	(6)	-	6 [16]	-
Restructuring provision	22	-	(22) [6]	-	-	-	-	-
Taxes, other than income taxes	29	-	-	29	29	-	-	29
Gain on sale of assets	-	-	-	-	-	(1) [4]	-	(1)
Net other operating (income) losses	25	- -	(38) [7, 18]	(13)	(14)	-	(1) [17, 18]	(15)
EBITDA	693	143	109	945	980	109	(53)	1,036
Depreciation and amortization	545	85 [2, 3]	-	630	538	60 [2, 3, 4]	-	598
Operating income	148	58	109	315	442	49	(53)	438
Finance lease income	58	(58) [1]	-	-	49	(49) [1]	-	-
Foreign exchange gain (loss)	4	-	8 [8]	12	-	-	4 [21]	4
Gain on sale of assets	262	-	(262) [9]	-	2	-	(2) [22]	-
Earnings (loss) before interest and taxes	472	-	(145)	327	493	-	(51)	442
Net interest expense	251	-	-	251	254	-	-	254
Income tax expense (recovery)	105	-	(107) [10, 11, 12, 13]	(2)	7	-	23 [10, 11]	30
Net earnings	116	-	(38)	78	232	-	(74)	158
Non-controlling interests	94	-	(14) [24]	80	50	-	(1) [23]	49
Net earnings (loss) attributable to TransAlta shareholders	22	-	(24)	(2)	182	-	(73)	109
Preferred share dividends	46	-	-	46	41	-	-	41
Net earnings (loss) attributable to common shareholders	(24)	-	(24)	(48)	141	-	(73)	68
Weighted average number of common shares outstanding in the year	280			280	273			273
Net earnings (loss) per share attributable to common shareholders	(0.09)			(0.17)	0.52			0.25

A reconciliation of comparable results to reported results for the year ended Dec. 31, 2013 is as follows:

Year ended Dec. 31	2013			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,292	47 (1, 2)	103 (5)	2,442
Fuel and purchased power	948	(58) (3)	-	890
Gross margin	1,344	105	103	1,552
Operations, maintenance, and administration	516	-	(5) (14)	511
Asset impairment reversal	(18)	-	18 (16)	-
Restructuring provision	(3)	-	3 (6)	-
Taxes, other than income taxes	27	-	-	27
Gain on sale of assets	-	(2) (4)	-	(2)
Net other operating (income) losses	102	-	(109) (17, 18, 19, 20)	(7)
EBITDA	720	107	196	1,023
Depreciation and amortization	525	61 (2, 3, 4)	(2) (14)	584
Operating income	195	46	198	439
Finance lease income	46	(46) (1)	-	-
Equity loss	(10)	-	-	(10)
Foreign exchange gain	1	-	-	1
Gain on sale of assets	12	-	(12) (22)	-
Earnings before interest and taxes	244	-	186	430
Net interest expense	256	-	-	256
Income tax recovery	(8)	-	34 (10, 11)	26
Net earnings (loss)	(4)	-	152	148
Non-controlling interests	29	-	-	29
Net earnings (loss) attributable to TransAlta shareholders	(33)	-	152	119
Preferred share dividends	38	-	-	38
Net earnings (loss) attributable to common shareholders	(71)	-	152	81
Weighted average number of common shares outstanding in the year	264			264
Net earnings per share attributable to common shareholders	(0.27)			0.31

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 are 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. 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 attempt to 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, 2015, Level III instruments had a net asset carrying value of $542 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, 2014.

2016 Financial Outlook

In consideration of low power prices in Alberta and the Pacific Northwest, anticipated lower cash interest, and higher distributions to non-controlling interest payments, the following table outlines our expectation on key financial targets for 2016:

Measure	Target
Comparable EBITDA	$990 million to $1,100 million
Comparable FFO	$755 million to $835 million
Comparable FCF	$250 million to $300 million
Dividend	$0.16 per share, 15 to 18 per cent payout of Comparable FCF

Market

For 2016, power prices in Alberta are expected to be comparable to 2015 as a result of persistent low natural gas prices, low demand growth, and the current level of supply. However, prices can vary based on supply and weather conditions. In the Pacific Northwest we expect power prices to be lower as well due to low natural gas prices. We do not have significant uncontracted positions in other jurisdictions.

Operations

Availability

Availability of our coal fleet in Canada is expected to be in the range of 87 to 89 per cent in 2016. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent.

Contracted Cash Flows

As a result of Alberta PPAs and long-term contracts, approximately 75 per cent of our capacity is contracted over the next two years. This is reduced to 65 per cent when our Alberta PPAs expire in 2017. More than half of our non-contracted generation is sold forward 12 to 18 months ahead of time using short-term physical or financial contracts, such that on an aggregated portfolio basis, depending on market conditions, we target being up to 90 per cent contracted for the upcoming calendar year. As at the end of 2015, approximately 87 per cent of our 2016 capacity was contracted. The average prices of our short-term physical and financial contracts for 2016 are approximately $50 per MWh in Alberta and approximately US$45 per MWh in the Pacific Northwest.

Fuel Costs

Mining costs at our Alberta coal mine are expected to decrease in 2016 due to effective cost control, and production improvements. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2016, on a standard cost per tonne basis, are expected to be one to two per cent lower than 2015 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 is purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered cost of fuel per MWh for 2016 is expected to decrease by approximately three per cent due to lower diesel surcharge costs on coal deliveries.

The value of coal inventories is assessed for impairment at the end of each reporting period. If the inventory is impaired, further charges are recognized in net earnings.

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. Energy Marketing historically contributes between $60 million to $80 million in gross margin.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the 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 partly offset our net foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2016 is expected to be lower than in 2015, primarily due to higher capitalized interest and lower debt balance. 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. Most of our debt is at fixed interest rates.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. Free cash flows generated by the business should be sufficient to support the construction of the South Hedland project station in 2016.

Income Taxes

The effective tax rate on earnings, excluding non-comparable items for 2016, is expected to be approximately 10 to 15 per cent, which is lower than the statutory tax rate of 26 per cent, due to changes in the amount of earnings between the jurisdictions in which pre-tax income is earned and the effect of certain deductions that do not fluctuate with earnings.

Capital Expenditures

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

Growth and Major Project Expenditures

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

	Total Project		2016	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
South Hedland power station[2]	589	242	113	Q2 2017	150 MW combined cycle power plant
Solomon load bank facility[3]	5	2	3	Q2 2016	Installation of 20 MW load bank facility required to complete the Solomon power station
Transmission	Not applicable [4]		13	Ongoing	Regulated transmission that receives a return on investment
Total	594	244	129		

(1) Represents amounts spent as of Dec. 31, 2015.

(2) Estimated project spend is AUD$570 million. Total estimated project spend is stated in CAD$ and includes estimated capital interest costs. The total estimated project spend may change due to fluctuation in foreign exchange rates.

(3) Includes certain natural gas conversion costs at the Solomon power station that will be recognized as a finance lease receivable. The total estimated project spend may change due to fluctuations in foreign exchange rates.

(4) Transmission projects are aggregated and develop on an ongoing basis. Consequently, discrete project spend is not available.

Sustaining and Productivity Expenditures

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 2014 *Restated* (1)	Spent in 2015	Expected spend in 2016
Routine capital	Capital required to maintain our existing generating capacity	135	101	100 - 105
Planned major maintenance	Regularly scheduled major maintenance	162	162	170 - 175
Mine capital	Capital related to mining equipment and land purchases	45	25	30 - 35
Finance leases	Payments on finance leases	10	13	15
Total sustaining capital excluding flood-recovery capital		**352**	**301**	**315 - 330**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	9	4	15 - 20
Total sustaining capital		**361**	**305**	**330 - 350**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	14	6	10 - 20
Total sustaining and productivity capital		**375**	**311**	**340 - 370**

The planned major maintenance for 2015 included $9 million associated with major maintenance at Poplar Creek, which was incurred prior to the close of the contractual restructuring. Our customer has assumed capital obligations of the facility arising after closing, and on an ongoing basis thereafter. Planned major outage for 2016 includes major turnaround of three units that we operate, and two that our partners operate. Our planned outage also includes significant work at our hydro facilities, including the Ghost river diversion and a stator/generator replacement.

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 2016:

	Coal	Gas and Renewables	Total
GWh lost	945 - 955	135 - 145	1,080 - 1,100

Financing

Financing for these capital expenditures is expected to be provided by cash flow from operating activities. We have access to approximately $1.4 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.

Sustainable Development Targets

Our 2016 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:

(1) *Restated to include hydro life extension from growth capital expenditures to sustaining capital expenditures. Refer to the Current Accounting Changes section of this MD&A.*

	Financial	Annual Performance Status
1. Maintain our investment grade rating	Achieve and maintain investment grade credit metrics.	Consistent with 2015 target
2. Increase focus on FFO and EBITDA	Deliver comparable EBITDA and comparable FFO for 2016 in the range of $990 million to $1,100 million and $755 million to $835 million respectively	6-8 per cent improvement from 2015

	Power Generating Portfolio	Annual Performance Status
3. Grow asset portfolio	Deliver an average of $40 million to $60 million of additional EBITDA from growth projects	Consistent with 2015 target
4. Achieve top quartile performance in Canadian Coal	Continue to deliver 87 to 89 per cent availability in the segment	Consistent with 2015 target in respect of the segment

	Human and Intellectual	Annual Performance Status
5. Reduce safety incidents	Achieve an Injury Frequency Rate (IFR) below 0.70	22 per cent improvement over 2015 target of 0.75
6. Manage employee turnover	Maintain voluntary turnover percentage under eight percent	Consistent with 2015 target
7. Support employee development	Achieve 100 per cent completion of development plans for all high-potential employees at the top three levels of the organization	Consistent with 2015 target
8. Enhance the capability of TransAlta leaders	Complete the final three stages of our globally recognized leadership development project to ensure TransAlta's top three tiers of leaders have the tools to successfully reposition and grow our business	New target

	Environmental	Annual Performance Status
9. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 13	28 per cent improvement over 2015 target (18)
10. Increase mine reclaimed acreage	Replace annual topsoil at Highvale Mine of 74 acres/year	Consistent with 2015 target (74 acres)
11. Utilize coal by-product	Sell a minimum of two million tonnes of coal by-product materials during the period 2015 to 2017	33 per cent achieved (long-term target)
12. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030	Consistent with 2015 (long-term target)
13. Reduce GHG emissions	20 per cent reduction from 2005 levels of TransAlta coal facility GHG by 2021, or the equivalent of 7,000,000 tonnes, of CO_2e per year	Consistent with 2015 target (long-term target)
	55 per cent reduction from 2005 levels of TransAlta coal facility GHG by 2030, or the equivalent of 19,700,000 tonnes, of CO_2e per year	Consistent with 2015 target (long-term target)

	Local Communities	Annual Performance Status
14. Combine stakeholder engagement	Implement final Stakeholder Engagement Framework. In 2016 every business unit will use a single framework for stakeholder guidance	New target
15. Support youth education with community investment	50 per cent of total communitiy investment spending will be directed to supporting youth education	New target
16. 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	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 Governance and Environment Committee (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 ("ERM") 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 which 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 Chief Executive Officer, Chief Financial Officer, Chief Legal and Compliance Officer, 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.

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 in regards to 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 corporate 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 Risk Management Committee ("RMC"). Reporting to the RMC includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion and 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, 2015 associated with our proprietary commodity risk management activities was $5 million (2014 - $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 2015. 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 are partially dependent upon the availability of their input resources in a given year. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- actively managing our assets and their condition through the generation segments 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 sensitivities of volumes to our net earnings are shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	19

Generation Equipment and Technology Risk

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could have a material adverse effect on the Corporation. Although our generation facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. Our plants are exposed to operational risks such as failures due to cyclic, thermal, and corrosion damage in boilers, generators, and turbines, and other issues that can lead to outages and increased volume risk. If plants do not meet availability or production targets specified in their PPA or other long-term contracts, we may be required to compensate the purchaser for the loss in the availability of production or record reduced energy or capacity payments. For merchant facilities, an outage can result in lost merchant opportunities. Therefore, an extended outage could have a material adverse effect on our business, financial condition, results of operations, or our cash flows.

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

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the availability of our generating facilities for the longest period of time;
- performing preventative maintenance on a regular basis;
- adhering to a comprehensive plant maintenance program and regular turnaround schedules;
- adjusting maintenance plans by facility to reflect the equipment type and age;
- having sufficient business interruption coverage in place in the event of an extended outage;
- having force majeure clauses in 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 replacement of selected generating assets.

Commodity Price Risk

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

We manage the financial exposure associated with fluctuations in electricity price risk by:

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided;
- maintaining a portfolio of short-, medium-, and long-term contracts to mitigate our exposure to short-term fluctuations in 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 2015, we had approximately 90 per cent (2014 - 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 fulfill our supply obligations under these short- and long-term contracts.

We manage the financial exposure to fluctuations in the costs of fuels used in production by:

- entering into long-term contracts that specify the price at which fuel is to be supplied to our plants;
- hedging emissions costs by entering into various emission trading arrangements; and
- selectively using hedges, where available, to set prices for fuel.

In 2015, 66 per cent (2014 - 68 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2014 - 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings, assuming production consistent with 2015 and applying the contractual profile in place at Dec. 31, 2015 for 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 mining operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At U.S. Coal, interruptions at our suppliers' 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. The coal used in generating activities in U.S. Coal is secured through long-term supply contracts;
- 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 and the U.S. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by imposing additional costs on the generation of electricity, such as emission caps 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 exceed 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;
- investing in clean coal technology development, which potentially provides long-term promise for large emission reductions from fossil-fuel-fired 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 Governance and Environment Committee.

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 fulfill its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

As at Dec. 31, 2015, we have liquidity of $1.4 billion comprised of amounts not drawn under our committed credit facility and cash on hand, and have no current need to draw in 2016.

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 fulfill its obligation or goes over its limits; and
- reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as 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, 2014. We had no material counterparty losses in 2015, and we are exposed to minimal credit risk for Alberta PPAs because under the terms of these arrangements, receivables are substantially all secured by letters of credit. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

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, 2015:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total Amount
Trade and other receivables(1)	90	10	100	567
Long-term finance lease receivables(2)	39	61	100	775
Risk management assets(1)	100	-	100	1,095
Total				2,437

(1) Letters of credit and cash are the primary types of collateral held as security related to these amounts.

(2) Includes balance of $446 million attributable to one non-investment-grade customer. 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 assessment takes into consideration the counterparty's financial position, external rating asessments, and how services are provided in an area of the counterparty's lower-cost operations, and TransAlta's other credit risk management practices.

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions, is $44 million (2014 - $29 million).

Currency Rate Risk

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

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

- hedging our net investments in foreign operations using a combination of foreign-denominated debt and financial instruments. Our strategy is to offset 90 to 100 per cent of all such foreign currency exposures. At Dec. 31, 2015, we have hedged approximately 93 per cent (2014 - 95 per cent) of our foreign currency net investment exposure, which we define to exclude net U.S. risk management assets;
- offsetting earnings from our foreign operations as much as possible by using expenditures denominated in the same foreign currencies and financial instruments to hedge the balance of this exposure; and
- entering into forward foreign exchange contracts to hedge future foreign-denominated receipts and expenditures, and all US-dollar-denominated debt outside of our net investment portfolio.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management's assessment that 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	2

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 maintaining stable investment grade credit ratings with three rating agencies. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlook, 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 adverse possible impacts identified above.

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 RMC, 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 while the opposite impact will be seen on 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, 2015, approximately nine per cent (2014 - four 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	1

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 methodology and processes;
- performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction;
- partnering with those who have previously been able to deliver projects economically and on budget,
- 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 2015, 54 per cent (2014 - 53 per cent) of our labour force was covered by 11 (2014 - 12) collective bargaining agreements. In 2015, two (2014 - four) agreements were renegotiated. We anticipate the successful negotiation of six collective agreements in 2016.

Regulatory and Political Risk

Regulatory and political risk describes the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market re-regulation, increased oversight and control, 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 the qualification of our renewable facilities in Alberta to the generation of tradable GHG allowances as part of the transition from the SGER to new regulation to be formulated to give effect to the 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, electric 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.

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	1

The effective tax rate on comparable earnings before income taxes, equity income, and other items for 2015 was 78 per cent (2014 – 19 per cent). The effective income tax rate can change depending on the mix of earnings from various countries and certain deductions that do not fluctuate with earnings.

Legal Contingencies

We are occasionally named as a party in various claims and legal proceedings that arise during the normal course of our business. We review each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in our favour or that such claims may not have a material adverse effect on us.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during 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 (the "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. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by 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, 2015 is an estimated upside of $156 million (2014 - $101 million upside) and downside of $211 million (2014 - $113 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $125 million upside (2014 - $76 million upside) and $186 million downside (2014 - $92 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$28 to US$45 for the period from 2018 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 re-allocation 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 regards to opportunities from combined talent and technology, functional organization and future growth potential, and we consider own performance measurement processes in making this determination.

As a result of our review in 2015 and other specific events, various analyses were run 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 2015, depreciation and amortization expense per the Consolidated Statements of Cash Flows was $605 million (2014 - $595 million), of which $59 million (2014 - $56 million) relates to mining equipment and is included in fuel and purchased power.

As a result of the announcement of Alberta's Climate Leadership Plan on Nov. 20, 2015, some of our coal plants may no longer operate as long as originally planned. We have not adjusted the useful life of these plants for depreciation, pending final ruling, and negotiations with the government in respect of compensation.

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.

As a result of the re-segmentation described in the Accounting Changes section of this MD&A, we re-allocated goodwill on a relative fair value basis. 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 2015 and 2014 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 $71 million (2014 - $45 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2015. 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 $647 million (2014 - $434 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2015. 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, 2015, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $233 million (2014 - $305 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.0 billion, which will be incurred between 2016 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	2

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

In January 2015, we completed changes to our internal reporting to systematize allocations of certain costs to each fuel type within our Generation Segment. This permitted internal reports regularly provided to the chief operating decision maker to be presented at the disaggregated fuel type level. Accordingly, commencing with first quarter 2015 reporting, we consider the following distinct fuel types as reportable segments: Canadian Coal, U.S. Coal, Gas, Wind, and Hydro. Previously, these were collectively reported as the Generation Segment. Comparative results for 2014 have been restated to align with the re-segmentation: general expenditures of the Generation Segment were allocated to each fuel type segment based on estimated relative benefit derived from those expenditures. For the years ended Dec. 31, 2014 and 2013, $12 million and $7 million, respectively, in expenditures associated with certain functions were determined to benefit the broader organization and were reassigned to the Corporate Segment. For the years ended Dec. 31, 2014 and 2013, $1 million and $3 million, respectively, in expenditures were determined to benefit the Energy Marketing Segment and were reassigned to that segment.

We have exercised judgment in aggregating the Corporation's Canadian gas and Australian gas operating segments together into a single reportable segment, Gas. The operating segments were determined to share the following similar economic characteristics: nature of revenue sources, level of contractedness, and customer assumption of fuel and regulatory compliance costs. In addition, the Canadian gas and Australian gas operating segments share substantial similarity in products (energy), processes (gas turbines), customers (industrial and regional utilities), and distribution methods (connection to grid or behind-the-fence generation). Commencing Sept. 1, 2015, the solar facilities acquired are included in the Wind and Solar Segment.

II. Change in Estimates – Useful Lives

During the first quarter, our subsidiary TA Cogen executed a new 15-year power supply contract with Ontario's IESO for the Windsor facility, which is effective Dec. 1, 2016. Accordingly, the useful life of the Windsor facility was extended prospectively to Nov. 30, 2031. As a result, depreciation expense for the year ended Dec. 31, 2015 decreased by $8 million.

III. Inventory Reclassification

During the fourth quarter of 2015, we finalized changes to our accounting system to improve tracking and management of parts, materials, and supplies that are expected to be consumed in the production process. Previously, these items were comprised in other capital spare parts. As a result, approximately $116 million was reclassified to inventory in current assets from PP&E. We restated the Consolidated Statement of Financial Position as at Dec. 31, 2014 to similarly reclassify parts, materials, and supplies to inventory in the amount of $125 million.

IV. Restatement of a Prior Quarter

During the fourth quarter of 2015, we restated the statement of earnings of the first quarter of 2015, to increase non-comparable deferred tax expense by $47 million. As a result, net earnings attributable to common shareholders of the first quarter of 2015 has decreased from $7 million to a net loss of $40 million. The adjustment is due to the correction of the tax basis of an internally transferred asset as part of the reorganization of companies giving effect to the Transaction with TransAlta Renewables. Comparative information of the first quarter of 2015 presented in this document has been adjusted accordingly.

V. Restatement of Prior Year Sustaining Capital

During 2015, we restated the hydro life extension capital spend, previously classified as growth capital, to sustaining capital, in order to align with the presentation of expenditures associated with projects of a similar nature made in 2015. As a result of the change, routine capital of the Hydro Segment increased by $19 million, $8 million, and $10 million, respectively, for 2014, 2013, and the fourth quarter of 2014. In consequence, comparable FCF was also reduced by these amounts for each period. Comparable FCF per share was adjusted accordingly.

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 9 *Financial Instruments*

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

Under the classification and measurement requirements for financial assets, financial assets must be classified and measured at either amortized cost or at fair value through profit or loss or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset.

The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

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

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

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

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In 2015, the effective date of IFRS 15 was delayed by one year. IFRS 15 is now effective for annual reporting periods beginning on or after Jan. 1, 2018 with early application permitted. We are assessing the impact of adopting this standard on our consolidated financial statements.

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.

We are assessing the impact of adopting this standard on our consolidated financial statements.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2015	2014 Restated (1)
Revenues	595	718
Comparable EBITDA(2)	268	301
Net earnings (loss) attributable to common shareholders	(7)	148
Comparable net earnings attributable to common shareholders(2)	3	46
Comparable funds from operations(2)	243	225
Cash flow from operating activities	118	250
Comparable FCF(2)	174	97
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.02)	0.54
Comparable net earnings per share(2)	0.01	0.17
Comparable FFO per share(2)	0.86	0.82
Comparable FCF per share(2)	0.61	0.35
Dividends declared per common share	0.18	0.18

Financial Highlights

- Comparable EBITDA for the fourth quarter of 2015 decreased by $33 million to $268 million compared to the same period in 2014, including an adjustment of $59 million to provisions. Excluding this non-cash adjustment relating mostly to prior year events, EBITDA would have been $327 million in the fourth quarter. This strong performance resulted from reductions to our operating expenses at our Highvale mine, solid availability in Canadian Coal, and the addition of wind, solar, and gas pipeline assets over the last year. Prices in Alberta averaged $21 per MWh during the fourth quarter of 2015, compared to $30 per MWh in the same period in 2014. Our strategy of being highly contracted generally limited the impacts of lower prices in Alberta, except for the wind and hydro facilities.
- Comparable FFO increased by $18 million for the three months ended Dec. 31, 2015 compared to the same period in 2014, as it excluded the effects of the provision adjustment discussed above.
- Fourth quarter comparable net earnings attributable to common shareholders was $3 million ($0.01 per share), down from comparable net earnings of $46 million ($0.17 per share) in the same quarter last year, due to lower comparable EBITDA described above, higher depreciation expense associated with the increased asset base, and an increase in non-controlling interest due to the Transaction with TransAlta Renewables.
- Reported net loss attributable to common shareholders was $7 million for the fourth quarter ($0.02 net loss per share) compared to net earnings of $148 million ($0.54 per share) for the same period in 2014. The differences between comparable and reported net earnings are mainly due to decreases (2014 - increases) in the fair value of de-designated and economic hedges at U.S. Coal. Reported net earnings of the fourth quarter of 2014 also included a large reversal of a writedown of deferred tax assets.

(1) Restated to deduct hydro life extension capital expenditures from comparable FCF. Refer to the Current Accounting Changes section of this document.

(2) 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 and Other Measures 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.

Segmented Operational Results

Comparable EBITDA and operational performance for the business is as follows:

Three months ended Dec. 31	2015	2014
Availability (%)(1)	**92.9**	93.2
Adjusted availability (%)(2)	**88.4**	93.2
Production (GWh)(1)	**11,107**	12,207
Comparable EBITDA		
Canadian Coal	**67**	119
U.S. Coal	**23**	19
Gas	**90**	80
Wind and Solar	**65**	56
Hydro	**19**	20
Energy Marketing	**26**	26
Corporate	**(22)**	(19)
Total comparable EBITDA	**268**	301

- Canadian Coal: Comparable EBITDA decreased $52 million to $67 million in the fourth quarter of 2015 compared to the same period in 2014. Fourth quarter EBITDA included a $59 million adjustment to provisions relating mostly to force majeure events from the periods between 2013 to 2015. Excluding this adjustment, 2015 EBITDA would have been $126 million for the quarter, slightly better than last year.
- U.S. Coal: Comparable EBITDA was $23 million in the fourth quarter compared to $19 million for the same period in 2014. The current quarter benefited from a full quarter of contract with Puget Sound Energy and of the appreciation of the US dollar in 2015.
- Gas: Comparable EBITDA was $90 million in the fourth quarter of 2015, an increase of $10 million, compared to the same period in 2014, primarily due to additional revenues from the Australian natural gas pipeline and the positive impact of the strengthening of the US dollar on a certain contract in Australia.
- Wind and Solar: Comparable EBITDA increased in the fourth quarter to $65 million compared to $56 million for the same period in 2014, primarily due to the contribution from assets acquired in 2015 and the impact of strengthening of the U.S. dollar on U.S. facilities.
- Hydro: Comparable EBITDA was consistent in the fourth quarter with the same period in 2014.
- Energy Marketing: Comparable EBITDA was consistent with the same period in 2014; with gross margin in both periods exceeded our quarterly expectations of $15 to $20 million per quarter.
- Corporate: Higher costs in our Corporate Segment is due to a provision associated with vacant leased office space following the corporate restructuring.

(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.

Availability and Production

Availability for the three months ended Dec. 31, 2015 was consistent with the same period in 2014. Lower production for the three months ended Dec. 31, 2015 compared to the same period in 2014 is primarily due to market curtailments at Canadian Coal.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO per share and comparable FCF per share are calculated as follows using the weighted average number of common shares outstanding during the period.

Three months ended Dec. 31	2015	2014 *Restated* [1]
Cash flow from operating activities	118	250
Change in non-cash operating working capital balances	76	(23)
Cash flow from operations before changes in working capital	194	227
Adjustments		
MSA settlement payment	31	-
Decrease in finance lease receivable	15	1
Payment of restructuring costs	11	-
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	(10)	(5)
Other non-comparable items	2	2
Comparable FFO	243	225
Deduct:		
Sustaining capital	(52)	(97)
Insurance recoveries of sustaining capital expenditures	23	3
Dividends paid on preferred shares	(11)	(13)
Distributions paid to subsidiaries' non-controlling interests	(29)	(21)
Comparable FCF	174	97
Weighted average number of common shares outstanding in the period	284	275
Comparable FFO per share	0.86	0.82
Comparable FCF per share	0.61	0.35

(1) Restated to include hydro life extension from Growth capital expenditures to sustaining capital expenditures. Refer to the Current Accounting Changes section of this document.

A reconciliation of comparable EBITDA to comparable FFO is as follows:

Three months ended Dec. 31	2015	2014
Comparable EBITDA	268	301
Unrealized gains from risk management activities	(6)	(12)
Interest expense	(63)	(58)
Provisions	76	-
Current income tax expense	(7)	(9)
Realized foreign exchange gain	1	14
Decommissioning and restoration costs settled	(4)	(5)
Non-cash gain on curtailment and amendment gain on empoyee future benefits	(8)	-
Capital insurance recoveries on Canadian Coal facility	(5)	-
Other non-cash items	(9)	(6)
Comparable FFO	243	225

Comparable FFO increased by $18 million in the fourth quarter of 2015 compared to the same period in 2014 as lower EBITDA in the quarter includes the non-cash impact of our adjustment to provisions.

Comparable FCF for the three months ended Dec. 31, 2015 increased $77 million to $174 million compared to the same period in 2014, primarily due to the increase in comparable FFO and a decrease in sustaining capital, partially offset by higher distributions paid to our subsidiaries' non-controlling interests as a result of the reduction of our interest in TransAlta Renewables.

Earnings on a Comparable Basis

During the fourth quarter of 2015, a restatement was made to tax expense impacting earnings reported in the first quarter of 2015. Refer to the Current Accounting Changes section of this MD&A for a description of this change.

The adjustments made to calculate comparable earnings for the three months ended Dec. 31, 2015 and 2014 are as follows. References are to the subsequent reconciliation table.

Three months ended Dec. 31			2015	2014
Reference number	Adjustment	Segment and fuel type		
Reclassifications:				
1	Finance lease income used as a proxy for operating revenue	Gas	17	13
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Gas	15	1
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	16	15
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Canadian Coal	-	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	13	(47)
6	Restructuring expense (recovery)	Canadian Coal	2	-
		Corporate	2	-
7	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	8	-
8	Net tax effect on comparable adjustments subject to tax	Unassigned	-	20
9	(Reversal) accrual of writedown of deferred income tax assets	Unassigned	6	(68)
10	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	(10)	(5)
11	Costs related to TAMA Transmission bid	Corporate	-	5
12	Asset impairment charges (reversals)	Gas	(1)	(5)
13	Non-comparable portion of insurance recovery received	Hydro	(18)	(3)
14	Foreign exchange on California claim	Unassigned	-	2
15	Non-comparable gain on sale of assets	Equity Investments	-	(1)
16	Non-comparable item attributable to non-controlling interest	Unassigned	7	-
17	Gain on Poplar Creek contract restructuring	Gas	1	-

A reconciliation of comparable results to reported results for the three months ended Dec. 31, 2015 and 2014 is as follows:

	Three months ended Dec. 31, 2015				Three months ended Dec. 31, 2014			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	595	32 (1, 2)	13 (5)	640	718	14 (1, 2)	(47) (5)	685
Fuel and purchased power	272	(16) (3)	-	256	268	(15) (3)	-	253
Gross margin	323	48	13	384	450	29	(47)	432
Operations, maintenance, and administration	109	-	10 (10)	119	138	-	- (10, 11)	138
Asset impairment charges (reversals)	(1)	-	1 (12)	-	(5)	-	5 (12)	-
Restructuring provision	4	-	(4) (6)	-	-	-	-	-
Taxes, other than income taxes	8	-	-	8	8	-	-	8
Gain on sale of assets	-	-	-	-	-	(1) (4)	-	(1)
Net other operating (income) losses	(29)	-	18 (13)	(11)	(17)	-	3 (13)	(14)
EBITDA	232	48	(12)	268	326	30	(55)	301
Depreciation and amortization	136	31 (2, 3)	-	167	136	17 (2, 3, 4)	-	153
Operating income	96	17	(12)	101	190	13	(55)	148
Finance lease income	17	(17) (1)	-	-	13	(13) (1)	-	-
Foreign exchange gain (loss)	3	-	8 (7)	11	7	-	2 (14)	9
Gain (loss) on sale of assets	(1)	-	1 (17)	-	1	-	(1) (15)	-
Earnings before interest and taxes	115	-	(3)	112	211	-	(54)	157
Net interest expense	69	-	-	69	62	-	-	62
Income tax expense (recovery)	(4)	-	(6) (8,9)	(10)	(26)	-	48 (8, 9)	22
Net earnings (loss)	50	-	3	53	175	-	(102)	73
Non-controlling interests	46	-	(7) (16)	39	14	-	-	14
Net earnings (loss) attributable to TransAlta shareholders	4	-	10	14	161	-	(102)	59
Preferred share dividends	11	-	-	11	13	-	-	13
Net earnings (loss) attributable to common shareholders	(7)	-	10	3	148	-	(102)	46
Weighted average number of common shares outstanding in the period	284			284	275			275
Net earnings (loss) per share attributable to common shareholders	(0.02)			0.01	0.54			0.17

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 2015 **Restated*	Q2 2015	Q3 2015	**Q4 2015**
Revenue	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	(0.14)	(0.47)	0.55	**(0.02)**
Comparable net earnings (loss) per share, basic and diluted	0.09	(0.16)	(0.12)	**0.01**

	Q1 2014	Q2 2014	Q3 2014	Q4 2014
Revenue	775	491	639	718
Comparable EBITDA	310	213	212	301
Comparable FFO	238	154	145	225
Net earnings (loss) attributable to common shareholders	49	(50)	(6)	148
Comparable net earnings (loss) attributable to common shareholders	47	(12)	(13)	46
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.18	(0.18)	(0.03)	0.54
Comparable net earnings (loss) per share, basic and diluted	0.17	(0.04)	(0.05)	0.17

** See Accounting Changes note for restatement.*

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. Market volatility can also impact quarterly contributions from our Energy Marketing Segment, as the first quarter of 2014 benefitted from exceptional weather conditions in northeastern North America. Following sales of non-controlling interest in TransAlta Renewables in the second quarter of 2014 and 2015 and the fourth quarter of 2015, an increasing portion of earnings is attributable to non-controlling interests.

Revenue is impacted by market and operational factors listed above, and by changes in future power prices in the Pacific Northwest, which cause de-designated and economic hedges in the region to fluctuate in value. These hedges significantly depreciated in the fourth quarter of 2013, in the second quarter of 2014, and in the first half of 2015, and significantly increased in value over the second half of 2014 and in the third quarter of 2015. Revenue of the fourth quarter of 2015 was also impacted by a significant increase to a provision related to Force Majeure events associated mostly to prior years.

Net earnings attributable to common shareholders have also been impacted by the following events:
- gain on disposal of assets, following the Poplar Creek contract restructuring in the third quarter of 2015;
- MSA provision in the third quarter of 2015;
- writedown of deferred tax assets in the first quarter of 2015 and a recovery in the third quarter of 2015;
- change in income tax rates in Alberta in the second quarter of 2015; and
- deferred income tax impacts of the Transaction in the first and second quarters of 2015.

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.

There has been no change in the internal control over financial reporting during the period covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of Dec. 31, 2015, the end of the period covered by this report, our disclosure controls and procedures were effective at a reasonable assurance level.

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

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

February 17, 2016

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 2015 consolidated financial statements of TransAlta included $637 million and $612 million of total and net assets, respectively, as of December 31, 2015, and $168 million and $19 million of revenues and net earnings, 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, 2015, 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, 2015, has also issued a report on internal control over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

February 17, 2016

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, 2015, 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 2015 consolidated financial statements of the Corporation and constituted $637 million and $612 million of total and net assets, respectively, as of December 31, 2015, and $168 million and $19 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, 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, 2015 and 2014, 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, 2015 of TransAlta Corporation and our report dated February 17, 2016 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

February 17, 2016

Report of Independent 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, 2015 and 2014, 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, 2015, 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, 2015 and 2014, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2015 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, 2015, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 17, 2016 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

February 17, 2016

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	2015	2014	2013
Revenues *(Note 33)*	2,267	2,623	2,292
Fuel and purchased power *(Note 5)*	1,008	1,092	948
Gross margin	1,259	1,531	1,344
Operations, maintenance, and administration *(Note 5)*	492	542	516
Depreciation and amortization	545	538	525
Asset impairment charges (reversals) *(Note 6)*	(2)	(6)	(18)
Restructuring provision *(Note 4)*	22	-	(3)
Taxes, other than income taxes	29	29	27
Net other operating (income) losses *(Note 8)*	25	(14)	102
Operating income	148	442	195
Finance lease income *(Note 7)*	58	49	46
Equity loss *(Note 4)*	-	-	(10)
Net interest expense *(Note 9)*	(251)	(254)	(256)
Foreign exchange gain	4	-	1
Gain on sale of assets *(Note 4)*	262	2	12
Earnings (loss) before income taxes	221	239	(12)
Income tax expense (recovery) *(Note 10)*	105	7	(8)
Net earnings (loss)	116	232	(4)
Net earnings (loss) attributable to:			
TransAlta shareholders	22	182	(33)
Non-controlling interests *(Note 11)*	94	50	29
	116	232	(4)
Net earnings (loss) attributable to TransAlta shareholders	22	182	(33)
Preferred share dividends *(Note 24)*	46	41	38
Net earnings (loss) attributable to common shareholders	(24)	141	(71)
Weighted average number of common shares outstanding in the year *(millions)*	280	273	264
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 23)*	(0.09)	0.52	(0.27)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	2015	2014	2013
Net earnings (loss)	116	232	(4)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	4	(20)	31
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	3	(1)	-
Reclassification of losses on derivatives designated as cash flow hedges to non-financial assets, net of tax(3)	-	-	1
Total items that will not be reclassified subsequently to net earnings	7	(21)	32
Gains on translating net assets of foreign operations	247	75	37
Reclassification of translation gains on net assets of divested foreign operations *(Note 4)*	(10)	(7)	-
Losses on financial instruments designated as hedges of foreign operations, net of tax(4)	(172)	(58)	(35)
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)	375	215	76
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(7)	(194)	(45)	(24)
Total items that will be reclassified subsequently to net earnings	252	187	54
Other comprehensive income	259	166	86
Total comprehensive income	375	398	82

Total comprehensive income attributable to:			
TransAlta shareholders	272	348	41
Non-controlling interests *(Note 11)*	103	50	41
	375	398	82

(1) Net of income tax recovery of nil for the year ended Dec. 31, 2015 (2014 - 7 recovery, 2013 - 11 expense).

(2) Net of income tax expense of 1 for the year ended Dec. 31, 2015 (2014 - nil, 2013 - nil).

(3) Net of income tax expense of 1 for the year ended Dec. 31, 2015 (2014 - nil, 2013 - 1 recovery).

(4) Net of income tax expense of 7 for the year ended Dec. 31, 2015 (2014 - 7 recovery, 2013 - 5 recovery).

(5) Net of income tax recovery of 1 for the year ended Dec. 31, 2015 (2014 - 1 recovery, 2013 - nil).

(6) Net of income tax expense of 138 for the year ended Dec. 31, 2015 (2014 - 91 expense, 2013 - 12 expense).

(7) Net of income tax expense of 50 for the year ended Dec. 31, 2015 (2014 - 3 expense, 2013 - 1 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	2015	2014 **Restated*
Cash and cash equivalents	54	43
Trade and other receivables *(Note 12)*	567	450
Prepaid expenses	26	17
Risk management assets *(Notes 13 and 14)*	298	273
Inventory *(Note 15)*	219	196
	1,164	979
Long-term portion of finance lease receivables	775	403
Property, plant, and equipment *(Note 16)*		
Cost	12,854	12,407
Accumulated depreciation	(5,681)	(5,294)
	7,173	7,113
Goodwill *(Note 17)*	465	462
Intangible assets *(Note 18)*	369	331
Deferred income tax assets *(Note 10)*	71	45
Risk management assets *(Notes 13 and 14)*	797	402
Other assets *(Note 19)*	133	98
Total assets	10,947	9,833
Accounts payable and accrued liabilities	334	481
Current portion of decommissioning and other provisions *(Note 20)*	166	34
Risk management liabilities *(Notes 13 and 14)*	200	128
Income taxes payable	3	2
Dividends payable *(Note 23)*	63	55
Current portion of long-term debt and finance lease obligations *(Note 21)*	87	751
	853	1,451
Credit facilities, long-term debt, and finance lease obligations *(Note 21)*	4,408	3,305
Decommissioning and other provisions *(Note 20)*	232	322
Deferred income tax liabilities *(Note 10)*	647	434
Risk management liabilities *(Notes 13 and 14)*	69	94
Defined benefit obligation and other long-term liabilities *(Note 22)*	348	349
Equity		
Common shares *(Note 23)*	3,075	2,999
Preferred shares *(Note 24)*	942	942
Contributed surplus	9	9
Deficit	(1,018)	(770)
Accumulated other comprehensive income *(Note 25)*	353	104
Equity attributable to shareholders	3,361	3,284
Non-controlling interests *(Note 11)*	1,029	594
Total equity	4,390	3,878
Total liabilities and equity	10,947	9,833

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

Commitments and contingencies *(Note 32)*

Subsequent events *(Note 34)*

See accompanying notes.

On behalf of the Board:

Gordon D. Giffin
Director

Alan J. Fohrer
Director

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

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

(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)*	2015	2014	2013
Operating activities			
Net earnings (loss)	116	232	(4)
Depreciation and amortization *(Note 33)*	605	595	585
Gain on sale of assets *(Note 4)*	(262)	(2)	(12)
California claim *(Note 8)*	-	(28)	28
Accretion of provisions *(Note 20)*	21	18	18
Decommissioning and restoration costs settled *(Note 20)*	(24)	(16)	(24)
Deferred income tax expense (recovery) *(Note 10)*	86	(26)	(47)
Unrealized (gain) loss from risk management activities	61	(50)	76
Unrealized foreign exchange (gain) loss	13	11	(1)
Provisions	101	-	11
Asset impairment charges (reversals) *(Note 6)*	(2)	(6)	(18)
Sundance Units 1 and 2 return to service *(Note 8)*	-	-	25
Equity loss, net of distributions received *(Note 4)*	-	-	10
Other non-cash items	(41)	(5)	44
Cash flow from operations before changes in working capital	674	723	691
Change in non-cash operating working capital balances *(Note 29)*	(242)	73	74
Cash flow from operating activities	432	796	765
Investing activities			
Additions to property, plant, and equipment *(Notes 16 and 33)*	(476)	(487)	(561)
Additions to intangibles *(Notes 18 and 33)*	(26)	(34)	(32)
Acquisition of renewable energy facilities, net of cash acquired (Note 4)	(101)	-	(109)
Addition to assets held for sale	-	(13)	(17)
Proceeds on sale of property, plant, and equipment	7	6	14
Proceeds on sale of investments and development projects *(Note 4)*	-	224	-
Realized gains (losses) on financial instruments	(12)	(2)	14
Decrease in finance lease receivable	23	3	1
Other	24	9	16
Change in non-cash investing working capital balances	(12)	2	(29)
Cash flow used in investing activities	(573)	(292)	(703)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 21)*	218	(436)	(119)
Repayment of long-term debt *(Note 21)*	(758)	(551)	(328)
Issuance of long-term debt *(Note 21)*	487	434	398
Dividends paid on common shares *(Note 23)*	(124)	(140)	(116)
Dividends paid on preferred shares *(Note 24)*	(46)	(41)	(38)
Net proceeds on issuance of preferred shares *(Note 24)*	-	161	-
Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)*	404	129	207
Realized gains on financial instruments	87	35	15
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	(99)	(84)	(55)
Decrease in finance lease obligations *(Note 21)*	(13)	(10)	(9)
Other	(7)	-	(2)
Cash flow from (used in) financing activities	149	(503)	(47)
Cash flow from (used in) operating, investing, and financing activities	8	1	15
Effect of translation on foreign currency cash	3	-	-
Increase in cash and cash equivalents	11	1	15
Cash and cash equivalents, beginning of year	43	42	27
Cash and cash equivalents, end of year	54	43	42
Cash income taxes paid	17	31	46
Cash interest paid	242	230	240

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 five generation segments of the Corporation are as follows: Canadian Coal, U.S. Coal, 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 investing 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 that are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board on Feb. 17, 2016.

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, U.S., or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign-denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rates in effect on the transaction date. The resulting translation gains and losses are included in Other Comprehensive Income (Loss) ("OCI") with the cumulative gain or loss reported in Accumulated Other Comprehensive Income (Loss) ("AOCI"). Amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in a foreign net investment as a result of a disposal, partial disposal, or loss of control.

C. Financial Instruments and Hedges

I. Financial Instruments

Financial assets and financial liabilities, including derivatives and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization. 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
Renewable generation	3-60 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction (see Note 2(S)). Upon commencement of commercial operations, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

H. Intangible Assets

Intangible assets acquired in a business combination are recognized separately from goodwill at their fair value at the date of acquisition. Intangible assets acquired separately are recognized at cost. Internally generated intangible assets arising from development projects are recognized when certain criteria related to the feasibility of internal use or sale, and probable future economic benefits of the intangible asset, are demonstrated.

Intangible assets are initially recognized at cost, which is comprised of all directly attributable costs necessary to create, produce, and prepare the intangible asset to be capable of operating in the manner intended by management.

Subsequent to initial recognition, intangible assets continue to be measured using the cost model, and are reported at cost less accumulated amortization and impairment losses, if any. Amortization is included in depreciation and amortization and fuel and purchased power in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use, and is computed on a straight-line basis over the intangible asset's estimated useful life, except for coal rights, which are amortized using a unit-of-production basis, based on the estimated mine reserves. Estimated useful lives of intangible assets may be determined, for example, with reference to the term of the related contract or licence agreement. The estimated useful lives and amortization methods are reviewed annually with the effect of any changes being accounted for prospectively.

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

Software	2-7 years
Power 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. 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 2013 to 2015 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).

As a result of the announcement of Alberta's Climate Leadership Plan on Nov. 20, 2015, some of the Corporation's coal plants may no longer operate as long as originally planned. The Corporation has not adjusted the useful life of these plants for depreciation, pending final ruling and negotiations with the government in respect of compensation.

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

In January 2015, the Corporation completed changes to its internal reporting to systematize allocations of certain costs to each fuel type within its generation segment. This permitted internal reports regularly provided to the chief operating decision maker to be presented at the disaggregated generation segment level. Accordingly, the Corporation considers the following distinct generation segments as reportable segments: Canadian Coal, U.S. Coal, Gas, Wind, and Hydro. Previously, these were collectively reported as the generation segment. Comparative results for 2014 and 2013 have been restated to align with the re-segmentation: general expenditures of the generation segment were allocated to each fuel type segment based on estimated relative benefit derived from those expenditures. For the years ended Dec. 31, 2014 and 2013, $12 million and $7 million, respectively, in expenditures associated with certain functions were determined to benefit the broader organization and were reassigned to the Corporate Segment. For the years ended Dec. 31, 2014 and 2013, $1 million and $3 million, respectively, in expenditures were determined to benefit the Energy Marketing Segment and were reassigned to that segment.

Management has exercised judgment in aggregating the Corporation's Canadian gas and Australian gas operating segments together into a single reportable segment, Gas. The operating segments were determined to share the following similar economic characteristics: nature of revenue sources, level of contractedness, and customer assumption of fuel and regulatory compliance costs. In addition, the Canadian gas and Australian gas operating segments share substantial similarity in products (energy), processes (gas turbines), customers (industrial and regional utilities), and distribution methods (connection to grid or behind-the-fence generation).

Commencing Sept. 1, 2015, the Wind Segment has been redefined as the Wind and Solar Segment, following the acquisition of solar facilities (Note 4).

II. Change in Estimates – Useful Lives

During the first quarter of 2015, the Corporation's subsidiary, TransAlta Cogeneration, L.P. ("TA Cogen"), executed a new 15-year power supply contract with Ontario's Independent Electricity System Operator for the Windsor facility, which is effective Dec. 1, 2016. Accordingly, the useful life of the Windsor facility was extended prospectively to Nov. 30, 2031. As a result, depreciation expense for the year ended Dec. 31, 2015 decreased by $8 million. The full year 2016 depreciation expense is expected to be lower by $9 million.

III. Inventory Reclassification

During the fourth quarter of 2015, the Corporation finalized changes to its accounting system to improve tracking and management of parts, materials, and supplies that are expected to be consumed in the production process. Previously, these items were comprised in other capital spare parts. As a result, approximately $116 million was reclassified to inventory in current assets from PP&E. The Corporation restated the Consolidated Statement of Financial Position as at Dec. 31, 2014 to similarly reclassify parts, materials, and supplies to inventory in the amount of $125 million.

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 9 *Financial Instruments*

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

Under the classification and measurement requirements, 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.

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

II. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In 2015, the IASB delayed the effective date of IFRS 15 by one year. IFRS 15 is now effective for annual reporting periods beginning on or after Jan. 1, 2018 with early application permitted. The Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

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 Corporation is assessing the impact of adopting this standard on its consolidated financial statements.

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. 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.

The Corporation's Poplar Creek cogeneration facility, which has a maximum capacity of 376 megawatts ("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 will provide 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 is accounted for as a joint operation.

The following table outlines the impacts of the transaction, 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 has been nominal. Had the acquisition taken place at the beginning of the year, the wind farms would have contributed $8 million to revenues and reduced earnings before tax by $2 million.

B. 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 ("SREC-I").

At the acquisition dates, the preliminary fair values of the identifiable assets and liabilities of Odin Wind Power LLC and RC Solar LLC were as follows:

Assets(1)	
Property, plant, and equipment	217
Inventory (SREC-I)	10
Net working capital	6
Total assets acquired	**233**
Liabilities(1)	
Non-recourse debt	55
Tax equity liability	50
Deferred tax liabilities(2)	18
Decomissioning and restoration provision	4
Total liabilities assumed	**127**
Total consideration transferred(1)	**106**

(1) The Corporation expects to finalize tax and net working capital reconciliations with the seller during the first half of 2016.

(2) 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 has been nominal. Had the acquisition taken place at the beginning of the year, the assets would have contributed $14 million to revenues and reduced earnings before taxes by $6 million.

C. Sale of Economic Interest in Australian Assets to TransAlta Renewables Inc.

On May 7, 2015, the Corporation closed the acquisition by TransAlta Renewables Inc. ("TransAlta Renewables") of an economic interest based on the cash flows of the Corporation's Australian assets (the "Transaction"). 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 (collectively, the "Portfolio"). 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.

D. Investment in Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility

On Nov. 23, 2015, the Corporation entered into an investment agreement with TransAlta Renewables, pursuant to which it has agreed to acquire an economic interest based on the cash flows of the Corporation's Sarnia cogeneration plant, Le Nordais wind farm, and Ragged Chute hydro facility (the "Canadian Assets") for a combined value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Quebec. TransAlta Renewables' investment consists of the acquisition of tracking preferred shares of a subsidiary of the Corporation that will provide TransAlta Renewables with an economic interest based on cash flows broadly equal to the underlying net distributable profits of the Canadian Assets. The Corporation will continue to own, manage, and operate the Canadian Assets.

TransAlta Renewables financed the investment through a combination of cash, unsecured debentures, and shares issued to the Corporation.

In order to fund the cash consideration payable to the Corporation, TransAlta Renewables issued 15,385,000 subscription receipts at a price of $9.75 per subscription receipt for gross proceeds of approximately $150 million. In addition, TransAlta Renewables granted an over-allotment option to the underwriters to purchase up to 2,307,750 subscription receipts at the same price for gross proceeds of up to approximately $23 million. The underwriters exercised in full the over-allotment option. The offering and the over-allotment option closed on Dec. 2, 2015. TransAlta Renewables received approximately $173 million in gross proceeds ($166 million in net proceeds). The proceeds from the sale of the subscription receipts have been directed to an escrow agent and invested in a demand deposit account with a Canadian chartered bank until the closing of this investment and that will be released to TransAlta Renewables upon the closing of this transaction. As at Dec. 31, 2015, a substantive closing condition remained outstanding and accordingly the investment in Canadian Assets and associated financing are not reflected in these financial statements.

On Jan. 6, 2016, the Corporation announced the closing of the investment in the Canadian Assets for a combined value of $540 million. Refer to Note 34 for further details.

E. Sale of TransAlta Renewables Shares to Alberta Investment Management Corporation

On Nov. 26, 2015, TransAlta 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.

F. Provision Adjustment

As part of its regular year-end process, the Corporation reviewed its provisions in respect of force majeure outages associated with its power purchase arrangements and as well as various other claims or disputes, including potential claims or disputes that may lead to litigation or arbitration. In 2015, following its review, the Corporation increased a provision by $66 million, including interest, as at Dec. 31, 2015. The adjustment decreased Canadian Coal revenue by $59 million and increased interest expense by $7 million.

G. 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.

H. 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.

I. Disposal of CE Generation, LLC

On June 12, 2014, the Corporation closed the sale of its 50 per cent ownership of CE Generation, LLC ("CE Gen"), CalEnergy LLC, and the Blackrock development project to MidAmerican Renewables for gross proceeds of 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.

J. Acquisition of Wyoming Wind Farm

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

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

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

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

K. Formation of TransAlta Renewables and Secondary Offering

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

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

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

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2015		2014		2013	
	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	**775**	**-**	937	-	778	-
Coal inventory writedown	**22**	**-**	19	-	22	-
Purchased power	**147**	**-**	75	-	85	-
Mine depreciation	**59**	**-**	56	-	58	-
Salaries and benefits	**5**	**250**	5	280	5	251
Other operating expenses	**-**	**242**	-	262	-	265
Total	**1,008**	**492**	1,092	542	948	516

6. Asset Impairment Charges and Reversals

A. 2015

The Corporation considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. The slowdown in the oil and gas sector has put Alberta into a recession, and 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 Greenhouse Gas ("GHG") emissions in the province. As at Dec. 31, 2015, the market capitalization of the Corporation was below the book value of its equity. The Government has stated intentions of providing compensation to coal-fired generators as part of its commitment to treat them fairly and not unnecessarily strand capital. The Corporation intends to negotiate an arrangement with the government.

As part of its monitoring controls, 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. These estimates are used to assess the significance of potential indicators of impairment and provide a criterion to evaluate adverse changes in operations.

During the fourth quarter, the Corporation completed a sensitivity analysis on these estimates 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.

The Corporation also 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.

Accordingly, there were no impairment charges made during the year ended Dec. 31, 2015. Impairment reversals of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

B. 2014

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 52.00 per MWh
On-highway diesel fuel on coal shipments	US$3.06 to 3.37 per gallon
Discount rates	5.1 to 6.2 per cent

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

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

II. Centralia Gas

During 2014, the Corporation sold to external counterparties and transferred to other owned facilities for productive use, assets of the Centralia gas facility 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.

C. 2013

I. Alberta Merchant

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

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

II. Renewables

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

7. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases, associated with the Fort Saskatchewan cogeneration facility, the Solomon power station, and, beginning in 2015, the Poplar Creek cogeneration facility, are as follows:

As at Dec. 31	2015		2014	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	121	116	55	51
Second to fifth years inclusive	414	326	229	157
More than five years	714	337	479	162
	1,249	779	763	370
Less: Unearned finance lease income	648	-	546	-
Add: Unguaranteed residual value	229	51	191	38
Total finance lease receivables	830	830	408	408

Included in the Consolidated Statements of Financial Position as:	2015	2014
Current portion of finance lease receivables *(Note 12)*	55	5
Long-term portion of finance lease receivables	775	403
	830	408

8. Net Other Operating Income and Losses

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

Year ended Dec. 31	2015	2014	2013
MSA settlement	56	-	-
Insurance recoveries	(31)	(10)	(8)
California claim	-	5	56
Supplier settlement	-	(9)	-
Sundance Units 1 and 2 return to service	-	-	25
Loss on assumption of pension obligations	-	-	29
Net other operating (income) losses	25	(14)	102

A. 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 Power Purchase Arrangement 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 has been paid in the fourth quarter, and the $25 million administrative penalty will be paid one year after this first payment. As a result of the approval, the Corporation has discontinued the appeal of the AUC's decision.

B. Insurance Recoveries

During 2015, the Corporation received $31 million in insurance recoveries (2014 - $10 million, 2013 - $8 million), of which $18 million (2014 - $4 million, 2013 - $1 million) relates to claims for the replacement and refurbishment of equipment for certain hydro facilities as a result of flooding in Southern Alberta in 2013 and $7 million in insurance proceeds relating to claims for repair costs on one of the Corporation's Canadian Coal facilities. The balance, in the amount of $6 million (2014 - $6 million, 2013 - $7 million), relates to business interruption insurance for various prior years' claims.

Additionally, $12 million (2014 - $18 million, 2013 - $7 million) 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.

C. 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.

D. Supplier Settlement

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

E. Sundance Units 1 and 2 Return to Service

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

F. Loss on Assumptions of Pension Obligations

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

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2015**	2014	2013
Interest on debt	**228**	238	240
Capitalized interest *(Note 16)*	**(9)**	(3)	(2)
Interest on finance lease obligations	**4**	1	-
Other *(Note 4)*	**7**	-	-
Accretion of provisions *(Note 20)*	**21**	18	18
Net interest expense	**251**	254	256

10. Income Taxes

A. Consolidated Statements of Earnings (Loss)

I. Rate Reconciliations

Year ended Dec. 31	2015	2014	2013
Earnings (loss) before income taxes	221	239	(12)
Equity loss	-	-	10
Net earnings attributable to non-controlling interests not subject to tax	(34)	(37)	(29)
Adjusted earnings (loss) before income taxes	187	202	(31)
Statutory Canadian federal and provincial income tax rate (%)	25.9	25.0	25.0
Expected income tax expense (recovery)	48	51	(8)
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	(16)	(3)	(21)
Deferred income tax expense related to temporary difference on investment in subsidiary	95	-	-
MSA settlement	14	-	-
Writedown (reversal of writedown) of deferred income tax assets	(56)	(5)	28
Statutory and other rate differences	20	-	(5)
Resolution of uncertain tax matters	-	(1)	(1)
Divestiture of investment	-	(38)	-
Other	-	3	(1)
Income tax expense (recovery)	105	7	(8)
Effective tax rate (%)	56	3	26

II. Components of Income Tax Expense

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

Year ended Dec. 31	2015	2014	2013
Current income tax expense	24	33	38
Adjustments in respect of current income tax of previous years	(5)	-	1
Adjustments in respect of deferred income tax of previous years	5	2	(1)
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	22	12	(68)
Deferred income tax expense related to temporary difference on investment in subsidiary(1)	95	-	-
Deferred income tax expense (recovery) resulting from changes in tax rates or laws(2)	20	-	(5)
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	-	(35)	(1)
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets(3)	(56)	(5)	28
Income tax expense (recovery)	105	7	(8)

Year ended Dec. 31	2015	2014	2013
Current income tax expense	19	33	39
Deferred income tax expense (recovery)	86	(26)	(47)
Income tax expense (recovery)	105	7	(8)

(1) In order to give effect to the Transaction with TransAlta Renewables, a reorganization of certain TransAlta companies was completed. The reorganization resulted in the recognition of a $95 million deferred tax liability on TransAlta's investment in a subsidiary. The deferred tax liability had not been recognized previously, as prior to the reorganization, the taxable temporary difference was not expected to reverse in the foreseeable future.

(2) During the second quarter of 2015, the Government of Alberta substantively enacted legislation to increase its provincial corporate income tax rate to 12 per cent from 10 per cent, effective July 1, 2015. This resulted in a net increase in the Corporation's deferred income tax liability of $18 million, of which $20 million is recorded in the Consolidated Statement of Earnings with an offsetting $2 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income.

(3) During the year ended Dec. 31, 2015, the Corporation reversed a previous writedown of deferred income tax assets of $56 million (2014 - $5 million writedown reversal, 2013 - $28 million writedown), of which $7 million during the year has been applied to offset an adjustment in respect of deferred income tax of prior periods. 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 utilize 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, 2015 and 2014 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	2015	2014	2013
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	88	88	12
Net impact related to net investment hedges	8	(8)	(5)
Net actuarial gains (losses)	-	(7)	11
Share issuance costs	(4)	(1)	-
Loss on sale of investment in subsidiary	(8)	-	-
Income tax expense reported in equity	84	72	18

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2015	2014
Net operating loss carryforwards	822	716
Future decommissioning and restoration costs	91	101
Property, plant, and equipment	(1,124)	(916)
Risk management assets and liabilities, net	(250)	(144)
Employee future benefits and compensation plans	70	68
Interest deductible in future periods	91	81
Foreign exchange differences on U.S.-denominated debt	74	48
Deferred coal revenues	16	14
Other deductible temporary differences	(4)	2
Net deferred income tax liability, before writedown of deferred income tax assets	(214)	(30)
Writedown of deferred income tax assets	(362)	(359)
Net deferred income tax liability, after writedown of deferred income tax assets	(576)	(389)

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

As at Dec. 31	2015	2014
Deferred income tax assets(1)	71	45
Deferred income tax liabilities	(647)	(434)
Net deferred income tax liability	(576)	(389)

(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, 2015, the Corporation had recognized a net liability of $7 million (2014 - $7 million) related to uncertain tax positions. The change in the liability for uncertain tax positions is as follows:

Balance, Dec. 31, 2013	(8)
Decrease as a result of settlements with taxation authorities	1
Balance, Dec. 31, 2014 and Dec. 31, 2015	(7)

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, 2015
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	37.96% - Public shareholders(1)
Kent Hills wind farm(2)	17% - Natural Forces Technologies Inc.

(1) As at Dec. 31, 2014, the non-controlling interest was 29.70%.

(2) Owned by TransAlta Renewables.

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 fluctuated since the formation of TransAlta Renewables as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Inception to Aug. 8, 2013	100	100
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	64.0	59.8

As the Class B shares issued to the Corporation in the Transaction 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	2015	2014	2013
Revenues	**236**	233	245
Net earnings	**198**	52	53
Total comprehensive income	**204**	52	54
Amounts attributable to the non-controlling interests:			
Net earnings	**63**	15	5
Total comprehensive income	**65**	15	5
Distributions paid to non-controlling interests	**43**	28	9

As at Dec. 31	2015	2014
Current assets	74	61
Long-term assets	3,262	1,903
Current liabilities	(190)	(241)
Long-term liabilities	(1,120)	(682)
Total equity	(2,026)	(1,041)
Equity attributable to non-controlling interests	(787)	(334)
Non-controlling interests' share (per cent)	37.96	29.7

B. TA Cogen

Year ended Dec. 31	2015	2014	2013
Results of operations			
Revenues	288	305	295
Net earnings	61	71	48
Total comprehensive income	77	72	71
Amounts attributable to the non-controlling interest:			
Net earnings	31	35	24
Total comprehensive income	38	35	36
Distributions paid to Canadian Power Holdings Inc.	56	56	46

As at Dec. 31	2015	2014
Current assets	82	58
Long-term assets	535	588
Current liabilities	(75)	(64)
Long-term liabilities	(54)	(59)
Total equity	(488)	(523)
Equity attributable to Canadian Power Holdings Inc.	(242)	(260)
Non-controlling interest share (per cent)	49.99	49.99

12. Trade and Other Receivables

As at Dec. 31	2015	2014
Trade accounts receivable	433	415
Income taxes receivable	5	5
Current portion of finance lease receivables *(Note 7)*	55	5
Collateral paid *(Note 14)*	74	25
Trade and other receivables	567	450

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, 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.

Carrying value as at Dec. 31, 2014

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

(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 (the "Policy"), which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. The Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

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	2015		2014	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	863	+125 -186	511	+76 -92
Long-term power sales - Alberta	(13)	+13 -7	(13)	+13 -8
Unit contingent power purchases	(70)	+9 -8	(53)	+9 -8
Structured products - Eastern U.S.	18	+6 -4	2	+1 -1
Hydro slice products - Western U.S.	(6)	+1 -4	-	- -
Others	(3)	+2 -2	(4)	+2 -4

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: 280 MW through Nov. 30, 2016, 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 2017, 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) and market indicators. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2015 are US$28 - US$45 (2014 - US$41 - US$50).

The contract is denominated in US dollars. With the continued strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2014 to Dec. 31, 2015, the base fair value and the sensitivity values have increased by approximately $136 million and $29 million, respectively, as a result of the currency movement.

ii. Long-Term Power Sales - 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 2020, 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, 2015 are $86 - $93 (2014 - $91 - $99).

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.

In particular, a one standard deviation movement upward and downward in the volumetric and price discount rates was assessed. 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, 2015 are 0 per cent to 2.8 per cent (2014 - 0.3 per cent to 1.5 per cent) and 1.7 per cent to 7.4 per cent (2014 - 0 per cent to 10 per cent), respectively.

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, 2015 are 85 per cent to 116 per cent and 65 per cent to 109 per cent (Dec. 31, 2014 – nil and 69 per cent to 103 per cent), respectively.

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, 2015 are 18 per cent to 71 per cent and 39 per cent to 80 per cent (Dec. 31, 2014 – 26 per cent to 86 per cent and 53 per cent to 82 per cent), respectively.

v. Hydro Slice Products – Western U.S.

The Corporation has 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 are accounted for as held for trading.

The key unobservable inputs used in the 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 50^{th} 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, 2015 and 2014, 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, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	-	(26)	354	-	56	(29)	-	30	325
Market price changes on new contracts	-	1	-	-	51	(48)	-	52	(48)
Contracts settled	-	26	(28)	-	(159)	76	-	(133)	48
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)

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

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2015 are primarily attributable to the following factors:

- maturities and increases in value related to market movements for power contracts in the Pacific Northwest (Level II non-hedge); and
- 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.

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 $214 million as at Dec. 31, 2015 (2014 - $115 million net asset) are classified as Level II fair value measurements. The significant changes in other risk management assets (liabilities) during the year ended Dec. 31, 2015 are primarily attributable to the strengthening 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, 2015	**-**	**4,067**	**-**	**4,067**	**4,344**
Long-term debt(1) - Dec. 31, 2014	-	4,091	-	4,091	3,918

(1) Includes current portion and excludes $69 million (Dec. 31, 2014 - $64 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	**2015**	2014	2013
Unamortized net gain at beginning of year	**188**	160	5
New inception gains	**28**	23	156
Change in foreign exchange rates	**28**	14	-
Amortization recorded in net earnings during the year	**(42)**	(9)	(1)
Unamortized net gain at end of year	**202**	188	160

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, 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

As at Dec. 31, 2014	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	(2)	-	93	91
Long-term	-	257	-	(10)	247
Net commodity risk management assets	-	255	-	83	338
Other					
Current	-	56	-	(2)	54
Long-term	-	55	6	-	61
Net other risk management assets (liabilities)	-	111	6	(2)	115
Total net risk management assets	-	366	6	81	453

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	2015				2014			
	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	534	1,048	(350)	(93)	578	608	(380)	(98)
Gross amounts set-off	(105)	(12)	105	12	(204)	(10)	204	10
Net amounts as presented in the Consolidated Statements of Financial Position	429	1,036	(245)	(81)	374	598	(176)	(88)

II. Hedges

a. Net Investment Hedges

The Corporation's hedges of its net investment in foreign operations are comprised of U.S.-dollar-denominated long-term debt with a face value of US$580 million (2014 - US$580 million) and the following foreign currency forward contracts:

As at Dec. 31	2015			2014			
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	AUD235	CAD221	-	2015
USD76	CAD104	(1)	2016	-	-	-	-

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

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	2015		2014	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	7,006	-	4,977	-
Natural gas *(GJ)*	-	22,485	963	32,113
Diesel *(gallons)*	-	-	-	6,720

During 2015, net unrealized pre-tax losses of $6 million (2014 - $3 million, 2013 - $1 million) were released from AOCI and recognized in earnings due to hedge de-designations for accounting purposes. All designated hedging relationships are effective as of Dec. 31, 2015.

During 2015, additional unrealized pre-tax gains of $3 million (2014 - $2 million, 2013 - nil) 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, 2015, cumulative gains of $4 million (2014 - $3 million) related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

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

As at Dec. 31		2015				2014	
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
CAD138	USD126	36	2016-2018	CAD194	USD180	16	2015-2018
AUD19	JPY1,683	1	2016-2017	AUD49	JPY4,522	(1)	2015-2017
Foreign Exchange Forward Contracts - foreign-denominated debt							
CAD95	USD70	2	2016-2018	CAD59	USD50	-	2015
Cross-Currency Swaps - foreign-denominated debt							
-	-	-	-	CAD530	USD500	50	2015
CAD434	USD400	116	2017	CAD434	USD400	28	2017
CAD306	USD270	72	2018	CAD192	USD180	18	2018

iii. Effect of Cash Flow Hedges

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

Year ended Dec. 31, 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
		Revenue	(110)	Revenue	5
Commodity contracts	308	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)

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

Over the next 12 months, the Corporation estimates that $38 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (2014 - 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	2015		2014		
Notional amount	Fair value asset	Maturity	Notional amount	Fair value asset	Maturity
USD50	5	2018	USD50	6	2018

Including interest rate swaps, 9 per cent of the Corporation's debt as at Dec. 31, 2015 is subject to floating interest rates (2014 - 4 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		2015	2014	2013
Derivatives in fair value hedging relationships	Location of gain (loss) recognized in earnings			
Interest rate contracts	Net interest expense	(1)	(1)	(2)
Long-term debt	Net interest expense	1	1	2
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	2015		2014	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	42,975	38,565	30,821	23,685
Natural gas *(GJ)*	106,203	101,100	156,898	198,969
Transmission *(MWh)*	-	5,014	-	3,904
Emissions *(tonnes)*	960	960	50	75

b. Other Non-Hedge Derivatives

As at Dec. 31		2015				2014	
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							
USD41	CAD54	(3)	2016-2018	CAD264	USD227	1	2015
AUD89	CAD79	(8)	2016-2020	AUD63	CAD61	1	2015
AUD5	USD4	1	2016	AUD47	USD40	3	2015-2016
-	-	-	-	AUD10	EUR7	-	2015
Derivatives embedded in supplier contracts [1]							
USD4	AUD5	(1)	2016	USD40	AUD47	(7)	2015-2016
-	-	-	-	EUR7	AUD10	-	2015

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

c. Total Return Swaps

The Corporation has certain compensation, 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, 2015, the Corporation recognized a net unrealized loss of $51 million (2014 - gain of $54 million, 2013 - loss of $40 million) related to commodity derivatives.

For the year ended Dec. 31, 2015, a loss of $1 million (2014 - gain of $10 million, 2013 - gain of $8 million) related to foreign exchange and other derivatives was recognized and is comprised of a net unrealized losses of $11 million (2014 - gain of $2 million, 2013 - loss of $1 million) and net realized gains of $10 million (2013 - gain of $8 million, 2013 - gain of $9 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 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, 2015 associated with the Corporation's proprietary trading activities was $5 million (2014 - $5 million, 2013 - $2 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 by-products, 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, 2015 associated with the Corporation's commodity derivative instruments used in generation hedging activities was $24 million (2014 - $27 million, 2013 - $42 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, 2015 associated with these transactions was $1 million (2014 - $7 million, 2013 - $11 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 (2014 - 15 basis point, 2013 - 25 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	2015		2014		2013	
	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	-	-	-	2	-

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

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the euro, 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 Transaction described in *Note 4*, the Corporation has 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$326 million remaining investments to fund the South Hedland project. In addition, the Corporation has 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 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 has entered into foreign currency hedges 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 hedges and accordingly the gain on the contracts, recognized as a foreign exchange loss, was $8 million for the year ended Dec. 31, 2015.

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 (2014 - four cent, 2013 - five cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2015		2014		2013	
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	2	5	4	5	2	8
AUD	(3)	-	(2)	-	-	-
Total	(1)	5	2	5	2	8

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.

(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty. TransAlta is exposed to minimal credit risk for Alberta Coal PPAs as receivables are substantially all secured by letters of credit.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for 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 or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2015:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total Amount
Trade and other receivables(1)	90	10	100	567
Long-term finance lease receivables(2)	39	61	100	775
Risk management assets(1)	100	-	100	1,095
Total				2,437

(1) Letters of credit and cash are the primary types of collateral held as security related to these amounts.

(2) Includes balance of $446 million attributable to one-non-investment grade customer. 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 assessment takes into consideration the counterparty's financial position, external rating asessments, and how services are provided in an area of the counterparty's lower-cost operations, and TransAlta's other credit risk management practices.

The Corporation's maximum exposure to credit risk at Dec. 31, 2015, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivable and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2015 was $44 million (2014 - $29 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 US bonds one notch from Baa3 to Ba1. As at Dec. 31, 2015 TransAlta maintains investment grade ratings with stable outlooks from three credit rating agencies, including BBB- by Standard & Poor's, BBB by DBRS, and BBB- by Fitch Ratings. 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:

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Accounts payable and accrued liabilities	334	-	-	-	-	-	334
Long-term debt[1]	72	604	947	761	447	1,596	4,427
Commodity risk management (assets) liabilities	(65)	(60)	(40)	(62)	(66)	(319)	(612)
Other risk management (assets) liabilities	(10)	(126)	(83)	4	1	-	(214)
Finance lease obligations	15	14	12	8	7	26	82
Interest on long-term debt and finance lease obligations[2]	225	216	171	138	106	796	1,652
Dividends payable	63	-	-	-	-	-	63
Total	**634**	**648**	**1,007**	**849**	**495**	**2,099**	**5,732**

(1) Excludes impact of hedge accounting and includes drawn credit facilities that are currently scheduled to mature in 2019.

(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, 2015, the Corporation provided $74 million (2014 - $25 million) in cash as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents.

II. Financial Assets Held as Collateral

At Dec. 31, 2015, the Corporation received $15 million (2014 - nil) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract.

II. 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, 2015, the Corporation had posted collateral of $220 million (Dec. 31, 2014 - $73 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 $44 million (Dec. 31, 2014 - $86 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	2015	2014 *(Restated)**
Parts and materials	116	125
Coal	56	39
Deferred stripping costs	14	15
Natural gas	8	12
Purchased emission credits	25	5
Total	**219**	196

** See Note 3A(III) for prior period restatements.*

The change in inventory is as follows:

Balance, Dec. 31, 2013	77
Net additions	14
Writedowns	(19)
Change in foreign exchange rates	(1)
Previously reported balance, Dec. 31, 2014	71
Transfer of parts and materials (*Note 3A(III)*)	125
Restated 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**

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, 2013	77	5,644	1,858	2,857	1,066	153	369	12,024
Additions	-	3	-	-	-	466	18	487
Additions - finance lease	-	-	-	-	58	-	-	58
Disposals	-	-	(34)	(1)	-	1	-	(34)
Impairment charges *(Note 6)*	-	-	-	(2)	-	-	-	(2)
Impairment reversals *(Note 6)*	-	-	9	2	-	-	-	11
Revisions and additions to decommissioning and restoration costs	-	11	4	(1)	10	-	-	24
Retirement of assets	-	(96)	(20)	(4)	(4)	-	-	(124)
Change in foreign exchange rates	2	92	4	7	4	(6)	3	106
Transfers	3	149	48	24	25	(273)	6	(18)
Previously reported balance, Dec. 31, 2014	82	5,803	1,869	2,882	1,159	341	396	12,532
Transfer of parts and materials *(Note 3)*	-		-	-	-	-	(125)	(125)
Restated balance, 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**
Accumulated depreciation								
As at Dec. 31, 2013	-	2,692	946	615	488	-	90	4,831
Depreciation	-	272	103	98	55	-	13	541
Retirement of assets	-	(84)	(19)	(1)	(2)	-	-	(106)
Disposals	-	-	(29)	-	-	-	-	(29)
Change in foreign exchange rates	-	61	4	1	3	-	-	69
Impairment reversals *(Note 6)*	-	-	3	-	-	-	-	3
Transfers	-	-	(15)	-	-	-	-	(15)
As at Dec. 31, 2014	-	2,941	993	713	544	-	103	5,294
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**
Carrying amount								
As at Dec. 31, 2013	77	2,952	912	2,242	578	153	279	7,193
As at Dec. 31, 2014	82	2,862	876	2,169	615	341	168	7,113
As at Dec. 31, 2015	**95**	**2,811**	**611**	**2,455**	**604**	**351**	**246**	**7,173**

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

The Corporation capitalized $9 million of interest to PP&E in 2015 (2014 - $3 million) at a weighted average rate of 5.83 per cent (2014 - 5.75 per cent).

In 2014, operations began at a processing facility that the Corporation contracted a third party to construct and operate. The facility recovers fine coal out of pond slurry at the Corporation's Centralia mine as part of restoration activities. Recovered coal fines can be used as fuel at the coal plant. As a result of certain contractual provisions, the Corporation recognized a finance lease asset and an obligation in the amount of estimated minimum lease payments of US$34 million, corresponding at inception to the penalties payable by the Corporation if it elects to terminate the agreement. Coal volume and slurry processing payments, net of the amortization and accretion of the financial lease obligation, are deemed to constitute contingent rents under the arrangement. Other finance lease additions in 2015 and 2014 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2015 was $81 million (2014 - $78 million).

17. Goodwill

As a result of the re-segmentation described in Note 3, the Corporation re-allocated goodwill on a relative fair value basis. 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.

As at Dec. 31	2014	2015	
Groups of CGUs	Previously recorded goodwill	**Segment**	**Re-allocated Goodwill**
		Hydro	**259**
Canadian Renewables and Alberta Merchant	417	**Wind and Solar**	**176**
U.S. Operations	15		
Energy Marketing	30	**Energy Marketing**	**30**
Total goodwill	462		**465**

For purposes of the 2015 and 2014 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 hydro segments (2014 - Canadian Renewables and Alberta Merchant CGUs) are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2015 models ranged between $26 to $311 per MWh during the forecast period (2014 - $31 to $276 per MWh). Discount rates used for the goodwill impairment calculation in 2015 ranged from 5.3 per cent to 6.5 per cent (2014 – 5.4 per cent to 6.9 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, 2013	178	180	186	22	566
Additions	-	8	-	26	34
Retirements	-	(3)	-	-	(3)
Change in foreign exchange rates	-	3	-	-	3
Transfers	-	18	-	(14)	4
As at Dec. 31, 2014	178	206	186	34	604
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**
Accumulated amortization					
As at Dec. 31, 2013	104	104	35	-	243
Amortization	2	21	8	-	31
Retirements	-	(3)	-	-	(3)
Change in foreign exchange rates	-	2	-	-	2
As at Dec. 31, 2014	106	124	43	-	273
Amortization	**3**	**20**	**9**	**-**	**32**
Change in foreign exchange rates	**-**	**3**	**-**	**-**	**3**
Transfers	**-**	**(5)**	**-**	**-**	**(5)**
As at Dec. 31, 2015	**109**	**142**	**52**	**-**	**303**
Carrying amount					
As at Dec. 31, 2013	74	76	151	22	323
As at Dec. 31, 2014	72	82	143	34	331
As at Dec. 31, 2015	**69**	**114**	**171**	**15**	**369**

19. Other Assets

The components of other assets are as follows:

As at Dec. 31	2015	2014
Deferred licence fees	16	16
Project development costs	42	29
Deferred service costs	17	18
Long-term prepaids, receivables, and other	52	29
Keephills Unit 3 transmission deposit	6	6
Total other assets	133	98

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.

Long-term prepaids, receivables, 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 six 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, 2013	270	62	332
Liabilities incurred	3	19	22
Liabilities settled	(16)	(31)	(47)
Accretion	18	-	18
Revisions in estimated cash flows	-	3	3
Revisions in discount rates	24	-	24
Reversals	-	(2)	(2)
Change in foreign exchange rates	6	-	6
Balance, Dec. 31, 2014	305	51	356
Liabilities incurred	6	58	64
Liabilities acquired *(Note 4)*	7	-	7
Liabilities settled	(24)	(14)	(38)
Liabilities disposed *(Note 4)*	(11)	(1)	(12)
Accretion	20	1	21
Revisions in estimated cash flows *(Note 4)*	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**

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2014	305	51	356
Current portion	28	6	34
Non-current portion	277	45	322
Balance, Dec. 31, 2015	**233**	**165**	**398**
Current portion	**30**	**136**	**166**
Non-current portion	**203**	**29**	**232**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.0 billion, which will be incurred between 2016 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2015, the Corporation had provided a surety bond in the amount of US$139 million (2014 - US$140 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2015, the Corporation had provided letters of credit in the amount of $115 million (2014 - $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, as disclosed in Note 4.

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	2015			2014		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	315	315	3.1%	96	96	2.8%
Debentures	1,044	1,051	6.0%	1,043	1,051	6.1%
Senior notes[3]	2,221	2,221	4.9%	2,444	2,436	4.9%
Non-recourse[4]	766	773	4.5%	380	383	5.9%
Other[5]	67	67	9.3%	19	19	5.9%
	4,413	4,427		3,982	3,985	
Finance lease obligations	82			74		
	4,495			4,056		
Less: current portion of long-term debt	(72)			(738)		
Less: current portion of finance lease obligations	(15)			(13)		
Total current long-term debt and finance lease obligations	(87)			(751)		
Total credit facilities, long-term debt, and finance lease obligations	**4,408**			3,305		

(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) US face value at Dec. 31, 2015 - US$1.6 billion (Dec. 31, 2014 - US$2.1 billion).

(4) Includes US$59 million at Dec. 31, 2015 (Dec. 31, 2014 - US$20 million).

(5) Includes US$36 million at Dec. 31, 2015 (Dec. 31, 2014 - nil) of tax equity financing.

Credit facilities are drawn on the Corporation's $1.5 billion committed syndicated bank credit facility and on the Corporation's US$300 million committed bilateral facility. The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's business. The Corporation's four-year revolving $1.5 billion committed syndicated credit facility, last renewed in June 2015, expires in 2019. The US$300 million bilateral credit facility has a four-year term to 2017. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, U.S. LIBOR, or U.S. base rate - in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million available in committed bilateral credit facilities, which expire in 2017.

Of the $2.2 billion (2014 - $2.1 billion) of committed credit facilities, $1.3 billion (2014 - $1.6 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 $1.3 billion available under the credit facilities, TransAlta also has $54 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 6.65 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.

In June 2014, the Corporation issued US$400 million of senior notes due in 2017 that carry a coupon rate of 1.90 per cent, payable semi-annually, at an issue price equal to 99.887 per cent of the principal amount of the notes.

A total of 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 2016 to 2028 and bear interest at rates ranging from 2.95 per cent to 7.3 per cent.

Non-recourse debentures have maturity dates ranging from 2016 to 2018 and bear interest rates ranging from 5.7 per cent to 7.3 per cent.

On Feb. 11, 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.

On Sept. 1, 2015, 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.

On Oct. 1, 2015, the Corporation 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). Notes payable for the Windsor plant matured and were paid out in November 2014.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2015, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

Non-recourse debentures of $230 million (2014 - $344 million) issued by the Corporation's CHD subsidiary include restrictive covenants requiring the proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures.

Other non-recourse debt of $536 million (2014 - $35 million) is secured by certain renewable generation facilities and subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by the facilities' operations. The total carrying amount of renewable generation facilities provided as security is $798 million at Dec. 31, 2015 (2014 - $50 million).

C. Principal Repayments

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Principal repayments[1]	72	604	947	761	447	1,596	**4,427**

(1) Excludes impact of derivatives and includes drawn credit facilities that are currently scheduled to expire in 2019.

D. Finance Lease Obligations

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

As at Dec. 31	2015		2014	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**18**	**18**	16	16
Second to fifth years inclusive	**49**	**44**	43	37
More than five years	**29**	**20**	30	21
	96	**82**	89	74
Less: interest costs	**14**	**-**	15	-
Total finance lease obligations	**82**	**82**	74	74

Included in the Consolidated Statements of Financial Position as:	2015	2014
Current portion of finance lease obligations	**15**	13
Long-term portion of finance lease obligations	**67**	61
	82	74

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, 2015 was $575 million (2014 - $396 million) with no (2014 - 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	**2015**	2014
Defined benefit obligation *(Note 27)*	**222**	226
Deferred coal revenues	**60**	58
Long-term incentive accruals *(Note 26)*	**8**	13
Other	**58**	52
Total	**348**	349

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 $11 million (2014 - $12 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	2015		2014	
	Common shares *(millions)*	Amount	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	275.0	3,001	268.2	2,916
Issued under the dividend reinvestment and share purchase plan	9.0	76	6.8	85
	284.0	3,077	275.0	3,001
Amounts receivable under Employee Share Purchase Plan	-	(2)	-	(2)
Issued and outstanding, end of year	284.0	3,075	275.0	2,999

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 23, 2013. As such, the Shareholder Rights Plan will expire unless it is approved by a majority of shareholders at the April 22, 2016 meeting. 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. These features were suspended on Jan. 14, 2016. Refer to Note 34 for further details.

On Jan. 1, 2016, 3.8 million common shares were issued for dividends reinvested.

D. Earnings per Share

Year ended Dec. 31	2015	2014	2013
Net earnings (loss) attributable to common shareholders	**(24)**	141	(71)
Basic and diluted weighted average number of common shares outstanding (millions)	**280**	273	264
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.09)**	0.52	(0.27)

E. Dividends

On Oct. 29, 2015, the Corporation declared a quarterly dividend of $0.18 per common share, payable on Jan. 1, 2016. On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually. Refer to Note 34 for further details.

On Feb. 16, 2016, the Corporation declared a quarterly dividend of $0.04 per share on common shares, payable on April 1, 2016.

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	**2015**		2014	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	12.0	293	12.0	293
Series C	11.0	269	11.0	269
Series E	9.0	219	9.0	219
Series G	6.6	161	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

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

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.

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

Characteristics specific to each first preferred share series as at Dec. 31, 2015, are as follows:

Series	Rate during term	Annual dividend rate per share (*$*)	First Rate Reset Date	Rate spread over Benchmark (*per cent*)	Convertible to Series
A	Fixed	1.15	March 31, 2016	2.03	B
B	Floating	-	-	2.03	A
C	Fixed	1.15	June 30, 2017	3.10	D
D	Floating	-	-	3.10	C
E	Fixed	1.25	Sept. 30, 2017	3.65	F
F	Floating	-	-	3.65	E
G	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 2015, 2014, and 2013:

	Total dividends declared ($)		
Series	**2015**	2014	2013
A	14	14	14
C	13	13	13
E	11	11	11
G[(1)]	8	3	-
Total for the year	**46**	41	38

(1) 2014 includes dividends for the period from issuance on Aug. 15, 2014 to Dec. 31, 2014.

On Feb. 16, 2016, the Corporation declared a quarterly dividend of $0.2875 per share on the Series A and Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable March 31, 2016.

25. Accumulated Other Comprehensive Income

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

	2015	2014
Currency translation adjustment		
Opening balance, Jan. 1	(19)	(36)
Gains on translating net assets of foreign operations, net of reclassifications to net earnings	237	68
Losses on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(1)	(166)	(51)
Balance, Dec. 31	52	(19)
Cash flow hedges		
Opening balance, Jan. 1	173	4
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(2)	177	169
Balance, Dec. 31	350	173
Employee future benefits		
Opening balance, Jan. 1	(50)	(30)
Net actuarial gains (losses) on defined benefit plans, net of tax(3)	4	(20)
Balance, Dec. 31	(46)	(50)
Others		
Opening balance, Jan. 1	-	-
Intercompany available for sale investments	(3)	-
Balance, Dec. 31	(3)	-
Accumulated other comprehensive income	353	104

(1) Net of income tax expense of 8 for the year ended Dec. 31, 2015 (2014 - 9 recovery).

(2) Net of income tax expense of 88 for the year ended Dec. 31, 2015 (2014 - 88 expense).

(3) Net of income tax recovery of nil for the year ended Dec. 31, 2015 (2014 - 7 recovery).

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 reversal of compensation expense related to PSUs and RSUs in 2015 was $3 million (2014 - $8 million expense, 2013 - $6 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 reversal of compensation expense related to the DSUs was $2 million in 2015 (2014 and 2013 - 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.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2015 are outlined below:

	Options outstanding and exerciseable		
Range of exercise prices *($ per share)*	Number of options at Dec. 31, 2015 *(millions)*	Weighted average remaining contractual life *(years)*	Weighted average exercise price *($ per share)*
22.46 - 28.81	0.6	4.1	23.76
31.97 - 48.02	0.5	2.1	34.63
22.46 - 48.02	**1.1**	**3.1**	**29.13**

No stock options were granted and no expense was recognized over the last three-year period.

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, 2015, amounts receivable from employees under the plan totalled $2 million (2014 - $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, 2015, 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, 2015.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the United States. The latest actuarial valuation for funding purposes of the Canadian registered plans was completed in early 2015 with an effective date of Dec. 31, 2014. The latest actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2015.

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 $65 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, 2013 and Jan. 1, 2015, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2015.

During 2015, the Corporation recognized a $5 million gain on amendment of the supplemental plan in connection with a reduction of benefits. The Corporation has also recognized a $3 million curtailment gain on other post-retirement benefit plans, due to the reduction in the number of employees, associated with the restructuring initiative described in Note 4.

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, 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	**-**	**(5)**	**(3)**	**(8)**
Defined benefit expense	**14**	**-**	**-**	**14**
Defined contribution expense	**21**	**-**	**-**	**21**
Net expense	**35**	**-**	**-**	**35**

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

Year ended Dec. 31, 2013	Registered	Supplemental	Other	Total
Current service cost	6	3	2	11
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(15)	-	-	(15)
Defined benefit expense	14	6	3	23
Defined contribution expense	20	-	-	20
Net expense	34	6	3	43

C. Status of Plans

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

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)

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

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, 2013	394	7	-	401
Interest on plan assets	18	-	-	18
Net return on plan assets	33	-	-	33
Contributions	14	5	1	20
Benefits paid	(33)	(4)	(1)	(38)
Administration expenses	(2)	-	-	(2)
Effect of translation on U.S. plans	3	-	-	3
Fair value of plan assets as at Dec. 31, 2014	427	8	-	435
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

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

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

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

Plan assets do not include any common shares of the Corporation at Dec. 31, 2015 and Dec. 31, 2014. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2015 (2014 - $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, 2013	517	74	27	618
Current service cost	6	2	2	10
Interest cost	23	4	1	28
Benefits paid	(33)	(4)	(1)	(38)
Actuarial (gain) loss arising from demographic assumptions	4	-	(2)	2
Actuarial gain arising from financial assumptions	50	8	3	61
Actuarial (gain) loss arising from experience adjustments	(5)	2	(1)	(4)
Effect of translation on U.S. plans	3	-	1	4
Present value of defined benefit obligation as at Dec. 31, 2014	565	86	30	681
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

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2015 is 13.5 years.

F. Contributions

The expected employer contributions for 2016 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	11	5	2	18

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, 2015			As at Dec. 31, 2014		
(per cent)	Registered	Supplemental	Other	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	3.8	3.6	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(1)	-	-	7.6(3)
Dental care cost escalation	-	-	4.0	-	-	4.0
Provincial health care premium escalation	-	-	5.0	-	-	5.0
Benefit cost for the year						
Discount rate	3.8	3.8	3.8	4.6	4.5	4.5
Rate of compensation increase	3.0	3.0	-	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	-	-	7.5(2)	-	-	7.8(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 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.

(2) 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.

(3) Post and Pre 65 rates; decreasing gradually to 5% by 2016-2019 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 2016-2019 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, 2015	Registered	Supplemental	Other	Pension	Other
1% decrease in the discount rate	73	12	2	3	1
1% increase in the salary scale	8	1	-	-	-
1% increase in the health care cost trend rate	-	-	2	-	1
10% improvement in mortality rates	17	3	-	1	-

28. Joint Arrangements

Joint arrangements at Dec. 31, 2015 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	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

29. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2015**	2014	2013
(Use) source:			
Accounts receivable	**(77)**	59	125
Prepaid expenses	**(3)**	(1)	(7)
Income taxes receivable	**1**	1	(14)
Inventory	**(9)**	7	15
Accounts payable, accrued liabilities, and provisions	**(152)**	8	(51)
Income taxes payable	**(2)**	(1)	6
Change in non-cash operating working capital	**(242)**	73	74

30. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2015	2014	Increase/ (decrease)
Long-term debt(1)	4,495	4,056	439
Equity			
Common shares	3,075	2,999	76
Preferred shares	942	942	-
Contributed surplus	9	9	-
Deficit	(1,018)	(770)	(248)
Accumulated other comprehensive income	353	104	249
Non-controlling interests	1,029	594	435
Less: available cash and cash equivalents(2)	(54)	(43)	(11)
Less: fair value asset of hedging instruments on long-term debt(3)	(190)	(96)	(94)
Total capital	8,641	7,795	846

(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 is 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, 2014 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, DBRS, and Fitch with stable outlooks. On Oct. 1, 2015, Moody's placed the rating of the Corporation's senior unsecured debt under review for possible downgrade. On Dec. 17, 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to support 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	2015	2014	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 (%)	**15.2**	16.9	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization (times)	**5.0**	4.2	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 interest income and capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares less interest income. Comparable FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. Comparable FFO to adjusted interest coverage in 2015 is consistent with 2014. 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 decreased in 2015 compared to 2014 due to lower comparable EBITDA and the impacts of the strengthening of the U.S. dollar on US-dollar-denominated debt. 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 2015 deteriorated compared to 2014 due to lower comparable EBITDA and the impacts of the strengthening of the U.S. dollar on US-dollar-denominated debt. 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 2015, the Corporation took several steps to strengthen its financial position and reduce debt, using proceeds from the dropdown of the Australian assets, the dropdown of the three Canadian Assets, and the sell-down of ownership interest in TransAlta Renewables to pay down credit facility borrowings, fund growth, and increase liquidity.

In 2014, the Corporation used the proceeds from the sale of CE Gen, Blackrock, CalEnergy, and Wailuku (see Note 4), the secondary offering of TransAlta Renewables common shares (see Note 4), and the offering of preferred shares (see Note 24) to pay down debt.

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, 2015 and 2014, net cash outflows, are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2015	2014	Increase (decrease)
Cash flow from operating activities	432	796	(364)
Change in non-cash working capital	242	(73)	315
Cash flow from operations before changes in working capital	674	723	(49)
Dividends paid on common shares	(124)	(140)	16
Dividends paid on preferred shares	(46)	(41)	(5)
Distributions paid to subsidiaries' non-controlling interests	(99)	(84)	(15)
Property, plant, and equipment expenditures(1)	(476)	(487)	11
Acquisitions	(101)	-	(101)
Outflow	(172)	(29)	(143)

(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, 2015, $1.3 billion (2014 - $1.6 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 raising non-recourse debt to fund upcoming corporate debt maturities.

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.

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

These activities supplement the equity offerings discussed in the preceding section.

31. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2015 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	66.61	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	2015	2014	2013
Total compensation	9	13	15
Comprised of:			
Short-term employee benefits	8	8	7
Post-employment benefits	2	2	2
Other long-term benefits	-	-	1
Termination benefits	1	-	2
Share-based payments	(2)	3	3

32. Commitments and Contingencies

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

	2016	2017	2018	2019	2020	2021 and thereafter	Total
Natural gas, transportation, and other purchase contracts	52	17	15	6	6	105	**201**
Transmission	14	8	9	7	7	6	**51**
Coal supply and mining agreements	151	46	50	50	52	542	**891**
Long-term service agreements	103	110	23	19	36	70	**361**
Non-cancellable operating leases	9	8	7	7	7	50	**88**
Growth	85	186	6	1	-	-	**278**
TransAlta Energy Bill	6	6	6	6	6	19	**49**
Total	420	381	116	96	114	792	1,919

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 2024.

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

D. Long-Term Service Agreements

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

E. Operating Leases

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

During the year ended Dec. 31, 2015, $9 million (2014 - $10 million, 2013 - $10 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2015 were 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, 2015, the Corporation has funded US$18 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.

33. Segment Disclosures

A. Description of Reportable Segments

The Corporation has seven reportable segments as described in Note 1. During 2015, the Corporation completed changes to its internal reporting to systematize allocations of certain costs to each fuel type within its generation segments. See Note 3 for further details.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2015	Canadian Coal	U.S. Coal	Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	371	569	250	116	49	-	2,267
Fuel and purchased power	441	311	229	19	8	-	-	1,008
Gross margin	471	60	340	231	108	49	-	1,259
Operations, maintenance, and administration	194	50	88	48	29	12	71	492
Depreciation and amortization	237	63	95	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	(57)	155	77	75	(23)	(103)	148
Finance lease income	-	-	58	-	-	-	-	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	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	1,023	422	692	247	131	108	-	2,623
Fuel and purchased power	492	251	326	14	9	-	-	1,092
Gross margin	531	171	366	233	122	108	-	1,531
Operations, maintenance, and administration	196	49	102	48	39	33	75	542
Depreciation and amortization	235	54	111	88	24	-	26	538
Asset impairment reversal	-	-	(6)	-	-	-	-	(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	65	155	91	66	70	(102)	442
Finance lease income	-	-	49	-	-	-	-	49
Gain on sale of assets								2
Net interest expense								(254)
Earnings before income taxes								239

Year ended Dec. 31, 2013 *(Restated - see Note 3)*	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Trading	Corporate	Total
Revenues	916	243	636	237	181	79	-	2,292
Fuel and purchased power	451	227	252	13	5	-	-	948
Gross margin	465	16	384	224	176	79	-	1,344
Operations, maintenance, and administration	203	48	97	38	36	21	73	516
Depreciation and amortization	232	56	107	79	27	1	23	525
Asset impairment charges (reversals)	-	-	1	(23)	4	-	-	(18)
Restructuring provision	(2)	-	-	-	-	-	(1)	(3)
Taxes, other than income taxes	11	4	3	5	3	-	1	27
Net other operating (gains) losses	54	-	(1)	-	(7)	56	-	102
Operating income (loss)	(33)	(92)	177	125	113	1	(96)	195
Finance lease income	-	-	46	-	-	-	-	46
Gain on sale of assets	-	-	-	-	-	-	12	12
Equity loss								(10)
Net interest expense								(256)
Foreign exchange gain								1
Loss before income taxes								(12)

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2015 are $20 million (2014 - $21 million, 2013 - $22 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 $230 million for the year ended Dec. 31, 2015 (2014 - $219 million, 2013 - $208 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2015	Canadian Coal	U.S. Coal	Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	-	-	-	176	259	30	-	465
PP&E	3,061	484	1,071	1,992	486	2	77	7,173
Intangible assets	92	6	15	176	3	17	60	369

As at Dec. 31, 2014	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Goodwill	-	-	-	173	259	30	-	462
PP&E *(Restated - Note 3)*	3,211	455	1,152	1,729	482	1	83	7,113
Intangible assets	91	5	12	145	3	14	61	331

III. Selected Consolidated Statements of Cash Flows Information

Year ended Dec. 31, 2015	Canadian Coal	U.S. Coal	Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:								
PP&E	179	13	223	13	43	1	4	476
Intangible assets	6	-	-	-	-	3	17	26

Year ended Dec. 31, 2014	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:								
PP&E	206	14	206	13	42	1	5	487
Intangible assets	2	-	7	-	-	8	17	34

Year ended Dec. 31, 2013	Canadian Coal	U.S. Coal	Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:								
PP&E	403	19	59	48	25	-	7	561
Intangible assets	3	-	-	-	1	7	21	32

Additions to non-current assets exclude amounts arising from acquisitions outlined in Note 4.

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	2015	2014	2013
Depreciation and amortization expense on the Consolidated Statements of Earnings	545	538	525
Depreciation included in fuel and purchased power *(Note 5)*	59	56	58
Loss on disposal of property, plant, and equipment	1	1	2
Depreciation and amortization on the Consolidated Statements of Cash Flows	**605**	595	585

C. Geographic Information

I. Revenues

Year ended Dec. 31	2015	2014	2013
Canada	1,705	1,989	1,898
U.S.	448	516	287
Australia	114	118	107
Total revenue	**2,267**	2,623	2,292

II. Non-Current Assets

As at Dec. 31	Property, plant, and equipment		Intangible assets		Other assets		Goodwill	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Canada	**5,898**	6,317	**328**	296	**79**	66	**417**	417
U.S.	**799**	532	**28**	25	**37**	14	**48**	45
Australia	**476**	264	**13**	10	**17**	18	**-**	-
Total	**7,173**	7,113	**369**	331	**133**	98	**465**	462

D. Significant Customer

During the year ended Dec. 31, 2015, sales to one customer in Canadian Coal represented 13 per cent of the Corporation's total revenue (2014 - 12 per cent).

34. Subsequent Events

A. Closing of Investment in Canadian Assets by TransAlta

On Jan. 6, 2016, the Corporation announced the closing of the investment in the Canadian Assets by TransAlta Renewables for a combined value of $540 million (see Note 4).

As consideration, TransAlta Renewables provided to the Corporation $172.5 million in cash, issued 15,640,583 common shares with a value of $152.5 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 30th and December 31st and will mature on Dec. 31, 2028. 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. The debenture is a direct unsecured obligation of TransAlta Renewables ranking subordinate to all liabilities, except liabilities which by their terms rank in rights of payment equally with or subordinate to the debenture. The debenture ranks equal with all subordinate debenture issued by TransAlta Renewables from time to time.

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 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 $1.2 million. On Jan. 6, 2016, TransAlta Renewables declared a dividend increase of 5 per cent.

B. Changes to Dividend Policies

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually and the suspension of the Premium Dividend™ , Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP") effective immediately. These actions were taken as part of a plan to maximize the Company's long-term financial flexibility, as well as to stop shareholder dilution relating to the DRIP.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2015	2014	2013
Financial Summary			
Statement of Earnings			
Revenues	**2,267**	2,623	2,292
Operating income	**148**	442	195
Net earnings (loss) attributable to common shareholders	**(24)**	141	(71)
Statement of Financial Position			
Total assets	**10,947**	9,833	9,624
Current portion of long-term debt, net of cash and cash equivalents	**33**	708	175
Credit facilities, long-term debt, and finance lease obligations	**4,408**	3,305	4,130
Non-controlling interests	**1,029**	594	517
Preferred shares	**942**	942	781
Equity attributable to common shareholders	**2,419**	2,342	2,125
Fair value (asset) liability of hedging instruments on debt	**(190)**	(96)	(16)
Total invested capital(1)	**8,641**	7,795	7,712
Cash Flows			
Cash flow from operating activities	**432**	796	765
Cash flow used in investing activities	**(573)**	(292)	(703)
Common Share Information *(per share)*			
Net earnings (loss)	**(0.09)**	0.52	(0.27)
Comparable earnings(2)	**(0.17)**	0.25	0.31
Dividends paid on common shares	**0.72**	0.83	1.16
Book value per common share *(at year-end)*	**8.52**	8.52	7.92
Market price:			
High	**12.34**	14.94	16.86
Low	**4.13**	9.81	12.91
Close *(Toronto Stock Exchange at Dec. 31)*	**4.91**	10.52	13.48
Ratios *(percentage except where noted)*			
Adjusted net debt to invested capital	**54.6**	56.3	60.7
Adjusted net debt to invested capital excluding non-recourse debt	**50.2**	54.1	58.7
Adjusted net debt to comparable EBITDA *(times)*(2)	**5.0**	4.2	4.6
Return on equity attributable to common shareholders	**(1.2)**	6.3	(3.2)
Comparable return on equity attributable to common shareholders(2)	**(2.3)**	3.0	3.7
Return on capital employed	**4.6**	5.8	2.8
Comparable return on capital employed(2)	**3.0**	5.1	5.2
Earnings coverage *(times)*	**1.5**	1.7	0.8
Dividend payout ratio based on comparable funds from operations(2)	**28.3**	26.4	43.1
Comparable EBITDA *(in millions of Canadian dollars)*(2)	**945**	1,036	1,023
Dividend coverage *(times)*	**3.6**	5.7	6.3
Dividend yield	**14.7**	7.9	8.6
Adjusted comparable funds from operations to adjusted net debt	**15.2**	16.9	15.2
Comparable funds from operations before interest to adjusted interest coverage *(times)*	**3.8**	3.8	3.7
Weighted average common shares for the year *(in millions)*	**280**	273	264
Common shares outstanding at Dec. 31 *(in millions)*	**284**	275	268
Statistical Summary			
Number of employees	**2,380**	2,786	2,772
Generating Capacity *(MW)*(3)			
Coal (Canadian and U.S.)	**5,126**	5,111	5,111
Gas(4)	**1,405**	1,531	1,779
Renewables (wind, solar and hydro)	**2,350**	2,204	2,202
Equity investments	**-**	-	396
Total generating capacity	**8,881**	8,846	9,488
Total generation production *(GWh)*	**40,673**	45,002	42,482

Financial data presented is based on IFRS. Financial data for 2009 and prior is based on Canadian GAAP. Prior year figures that appear within the MD&A have been restated to conform with the current year's presentation. All other prior year figures have not been restated.

(1) Total invested capital for 2014 to 2009 has been revised to align with the 2015 calculation methodology.
(2) These ratios were calculated using non-IFRS measures. Periods for which the non-IFRS measure was not previously disclosed have not been calculated.
(3) 2015, 2014, 2013, and 2012 are gross capacity which reflects the basis of underlying results. Prior year figures are as previously reported.
(4) Includes finance leases.

Ratio Formulas

Adjusted net debt to invested capital = long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents / long-term debt and finance lease obligations including current portion + non-controlling interests + equity attributable to shareholders - 50 per cent issued preferred shares - cash and cash equivalents

Adjusted net debt to comparable EBITDA= long-term debt and finance lease obligations including current portion and fair value (asset) liability of hedging instruments on debt - cash and cash equivalents + 50 per cent issued preferred shares / comparable EBITDA

Return on equity attributable to common shareholders = net earnings attributable to common shareholders excluding gain on discontinued operations or earnings on a comparable basis / equity attributable to common shareholders excluding Accumulated Other Comprehensive Income ("AOCI")

2012	2011	2010	2009	2008	2007	2006	2005
2,210	2,618	2,673	2,770	3,110	2,775	2,677	2,664
(214)	645	487	378	533	541	157	421
(615)	290	255	181	235	309	45	199
9,503	9,780	9,635	9,762	7,815	7,157	7,460	7,741
582	284	202	(51)	194	600	296	(66)
3,610	3,721	3,823	4,411	2,564	1,837	2,221	2,605
330	358	431	478	469	496	535	559
-	-	-	-	-	-	175	175
3,018	3,274	3,120	2,929	2,510	2,299	2,428	2,543
50	32	41	16	-	-	-	-
7,590	7,669	7,617	7,783	5,737	5,232	5,655	5,816
520	690	838	580	1,038	847	490	619
(1,048)	(608)	(765)	(1,598)	(581)	(410)	(261)	(242)
(2.62)	1.31	1.16	0.90	1.18	1.53	0.22	1.01
0.50	1.05	0.97	0.90	1.46	1.31	1.16	0.88
1.16	1.16	1.16	1.16	1.08	1.00	1.00	1.00
8.78	12.08	12.85	13.41	12.70	11.39	11.99	12.80
21.37	23.24	23.98	25.30	37.50	34.00	26.91	26.66
14.11	19.45	19.61	18.11	21.00	23.79	20.22	17.67
15.12	21.02	21.15	23.48	24.30	33.35	26.64	25.41
61.0	52.5	53.1	56.1	48.1	46.8	44.5	43.9
59.0	60.0	50.7	52.6	45.6	44.0	41.0	39.9
4.6	3.8	-	-	-	-	-	-
(25.9)	10.6	9.6	6.9	9.4	13.1	1.8	7.0
4.9	8.4	8.0	6.9	11.6	10.5	9.2	6.8
(3.1)	8.3	6.6	5.7	7.7	9.8	2.4	7.1
5.3	7.0	6.0	5.8	9.6	9.7	9.0	7.4
(1.0)	2.7	2.2	1.9	2.8	3.3	0.5	2.3
25.1	24.0	39.6	-	-	-	-	-
1,015	1,044	955	888	1,006	980	-	-
4.7	3.5	4.0	2.6	4.8	4.2	2.4	3.1
7.7	5.5	5.5	4.9	4.4	3.0	3.8	3.9
16.7	20.1	19.6	20.5	31.7	30.7	26.2	23.0
3.3	4.4	4.6	4.9	7.2	6.6	5.5	4.7
235	222	219	201	199	202	201	197
255	224	220	218	198	201	202	199
2,084	2,235	2,389	2,343	2,200	2,201	2,687	2,657
4,551	4,325	4,688	4,967	4,942	4,942	4,887	4,885
1,731	1,567	1,648	1,843	1,913	1,960	1,953	1,933
2,058	1,974	1,950	1,965	1,218	1,122	1,122	1,117
390	390	390	-	-	-	-	-
8,730	8,256	8,676	8,775	8,073	8,024	7,962	7,935
38,750	41,012	48,614	45,736	48,891	50,395	48,213	51,810

Earnings coverage = net earnings attributable to shareholders + income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Return on capital employed = earnings before non-controlling interests and income taxes + net interest expense or comparable earnings before non-controlling interests and income taxes + net interest expense / invested capital excluding AOCI

Dividend yield = dividends paid per common share / current year's close price

Dividend payout ratio = common share dividends declared / comparable funds from operations - 50 per cent dividends paid on preferred shares.

Comparable funds from operations before interest to adjusted interest coverage = comparable funds from operations + interest on debt - interest income - capitalized interest / interest on debt + 50 per cent dividends paid on preferred shares - interest income

Dividend coverage = comparable cash flow from operating activities / cash dividends paid on common shares

Adjusted comparable funds from operations to adjusted net debt = comparable funds from operations - 50 per cent dividends paid on preferred shares/ period end long-term debt and finance lease obligations including fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents

Comparable EBITDA = operating income + depreciation and amortization per the Consolidated Statements of Cash Flows +/- non-comparable items

Plant Summary

As of January 2016	Facility	Capacity (MW)[1]	Ownership (%)	Net capacity ownership interest (MW)[1][2]	Region	Revenue source	Contract expiry date
Coal 6 Facilities	Sundance, AB	2,141	100%	2,141	Western Canada	Alberta PPA[3]/ Merchant[4]	2017-2020
	Keephills, AB	790	100%	790	Western Canada	Alberta PPA/ Merchant[5]	2020
	Keephills 3, AB	463	50%	232	Western Canada	Merchant	-
	Genesee 3, AB	466	50%	233	Western Canada	Merchant	-
	Sheerness, AB	780	25%	195	Western Canada	Alberta PPA	2020
	Centralia, WA	1,340	100%	1,340	United States	LTC/Merchant	2020-2025[6]
Total Coal		**5,980**		**4,931**			
Gas 13 Facilities	Poplar Creek, AB	230	100%	230	Western Canada	LTC[7]	2030
	Fort Saskatchewan, AB	118	30%	35	Western Canada	LTC	2019
	Sarnia, ON	506	100%	506	Eastern Canada	LTC	2022-2025
	Mississauga, ON	108	50%	54	Eastern Canada	LTC	2018
	Ottawa, ON	74	50%	37	Eastern Canada	LTC/Merchant	2017-2033
	Windsor, ON	72	50%	36	Eastern Canada	LTC/Merchant	2031
	Southern Cross, WA[8][9]	245	100%	245	Australia	LTC	2023
	South Hedland, WA[9][10]	150	100%	150	Australia	LTC	2042
	Solomon, WA[9]	125	100%	125	Australia	LTC	2028
	Parkeston, WA	110	50%	55	Australia	LTC	2026
Total Gas		**1,738**		**1,473**			
Wind 22 Facilities	Summerview 1, AB	70	100%	70	Western Canada	Merchant	-
	Summerview 2, AB	66	100%	66	Western Canada	Merchant	-
	Ardenville, AB	69	100%	69	Western Canada	Merchant	-
	Blue Trail, AB	66	100%	66	Western Canada	Merchant	-
	Wintering Hills, AB	88	51%	45	Western Canada	Merchant	-
	Castle River, AB[11]	44	100%	44	Western Canada	Merchant	-
	McBride Lake, AB	75	50%	38	Western Canada	LTC	2024
	Soderglen, AB	71	50%	35	Western Canada	Merchant	-
	Cowley Ridge, AB	16	100%	16	Western Canada	Merchant	-
	Cowley North, AB	20	100%	20	Western Canada	Merchant	-
	Sinnott, AB	7	100%	7	Western Canada	Merchant	-
	Macleod Flats, AB	3	100%	3	Western Canada	Merchant	-
	Melancthon, ON[12]	200	100%	200	Eastern Canada	LTC	2026-2028
	Wolfe Island, ON	198	100%	198	Eastern Canada	LTC	2029
	Kent Breeze, ON	20	100%	20	Eastern Canada	LTC	2031
	Kent Hills, NB[12]	150	83%	125	Eastern Canada	LTC	2033-2035
	Le Nordais, QC	98	100%	98	Eastern Canada	LTC	2033
	New Richmond, QC	68	100%	68	Eastern Canada	LTC	2033
	Wyoming Wind, WY	144	100%	144	United States	LTC	2028
	Lakeswind, MN	50	100%	50	United States	LTC	2034
Total Wind		**1,521**		**1,379**			
Solar 1 Facility	Mass Solar, MA[13]	21	100%	21	United States	LTC	2032-2045
Total Solar		**21**		**21**			
Hydro 27 Facilities	Brazeau, AB	355	100%	355	Western Canada	Alberta PPA	2020
	Big Horn, AB	120	100%	120	Western Canada	Alberta PPA	2020
	Spray, AB	112	100%	112	Western Canada	Alberta PPA	2020
	Ghost, AB	54	100%	54	Western Canada	Alberta PPA	2020
	Rundle, AB	50	100%	50	Western Canada	Alberta PPA	2020
	Cascade, AB	36	100%	36	Western Canada	Alberta PPA	2020
	Kananaskis, AB	19	100%	19	Western Canada	Alberta PPA	2020
	Bearspaw, AB	17	100%	17	Western Canada	Alberta PPA	2020
	Pocaterra, AB	15	100%	15	Western Canada	Merchant	-
	Horseshoe, AB	14	100%	14	Western Canada	Alberta PPA	2020
	Barrier, AB	13	100%	13	Western Canada	Alberta PPA	2020
	Taylor, AB	13	100%	13	Western Canada	Merchant	-
	Interlakes, AB	5	100%	5	Western Canada	Alberta PPA	2020
	Belly River, AB	3	100%	3	Western Canada	Merchant	-
	Three Sisters, AB	3	100%	3	Western Canada	Alberta PPA	2020
	Waterton, AB	3	100%	3	Western Canada	Merchant	-
	St. Mary, AB	2	100%	2	Western Canada	Merchant	-
	Upper Mamquam, BC	25	100%	25	Western Canada	LTC	2025
	Pingston, BC	45	50%	23	Western Canada	LTC	2023
	Bone Creek, BC	19	100%	19	Western Canada	LTC	2031
	Akolkolex, BC[14]	10	100%	10	Western Canada	LTC	2015
	Ragged Chute, ON	7	100%	7	Eastern Canada	LTC	2029
	Misema, ON	3	100%	3	Eastern Canada	LTC	2027
	Galetta, ON	2	100%	2	Eastern Canada	LTC	2030
	Appleton, ON	1	100%	1	Eastern Canada	LTC	2030
	Moose Rapids, ON	1	100%	1	Eastern Canada	LTC	2030
	Skookumchuck, WA	1	100%	1	United States	LTC	2020
Total Hydro		**948**		**926**			
Total		**10,208**		**8,730**			

(1) Megawatts are rounded to the nearest whole number; columns may not add due to rounding.
(2) Accounts for 100% of TransAlta Renewables assets. As of January 6, 2016, TransAlta owns approximately 64% of the outstanding voting shares of TransAlta Renewables.
(3) PPA refers to Power Purchase Arrangement.
(4) Merchant capacity refers to uprates on unit 3 (15 MW), unit 4 (53 MW), unit 5 (53 MW), and unit 6 (44 MW).
(5) Merchant capacity refers to uprates on unit 1 (12 MW) and unit 2 (12 MW).
(6) Contract is in place until 2025; however, one unit is set to retire in 2020.
(7) LTC refers to Long-Term Contract.
(8) Comprised of four facilities.
(9) Gas/diesel.
(10) Plant is under construction and expected to be fully commissioned in mid-2017.
(11) Includes seven individual turbines at other locations.
(12) Comprised of two facilities.
(13) Comprised of four ground-mounted projects and four roof-top projects.
(14) Contract terms remain unchanged until the renewal process is finalized.

Sustainability Performance Indicators

Corporate Statistics

	Environment, Health and Safety Management Systems	2015	2014	2013
1	Facilities with ISO 14001 and/or OHSAS 18001-based management systems[1]	**67**	62	62
2	Generation capacity with ISO 14001 and OHSAS 18001-based management systems *(%)*	**97**	98	98
3	Management system audits[2]	**8**	9	14
4	Compliance audits[3]	**9**	9	14
5	Special audits[4]	**6**	8	0

	Environmental Performance	2015	2014	2013
	Air Emissions[5]			
6	Sulphur dioxide *(tonnes)* ✓	**41,800**	47,600	36,200
7	Sulphur dioxide emission intensity *(kg/MWh)*[6] ✓	**1.13**	1.20	1.00
8	Nitrogen oxide *(tonnes)* ✓	**48,000**	52,900	42,900
9	Nitrogen oxide emission intensity *(kg/MWh)*[6] ✓	**1.30**	1.34	1.19
10	Particulate matter *(tonnes)* ✓	**4,900**	5,200	3,300
11	Particulate matter emission intensity *(kg/MWh)*[6] ✓	**0.13**	0.13	0.09
12	Mercury *(kilograms)* ✓	**170**	220	170
13	Mercury emission intensity *(mg/MWh)*[6] ✓	**4.50**	5.66	4.77
	Greenhouse Gas Emissions[7]			
14	Carbon dioxide *(tonnes CO_2e)* ✓	**31,902,700**	34,724,400	30,417,500
15	Methane *(tonnes CO_2e)* ✓	**112,600**	119,200	92,800
16	Nitrous oxide *(tonnes CO_2e)* ✓	**212,400**	231,200	199,100
17	Sulfur hexafluoride *(tonnes CO_2e)*[8]	**18**	10	10
18	Gross emissions totals *(tonnes CO_2e)*[9] ✓	**32,227,700**	35,074,800	30,709,400
19	Gross emission intensity *(kg CO_2e/MWh)*[10] ✓	**0.87**	0.89	0.85
20	Scope 1 GHG emissions[11] ✓	**32,041,400**	34,892,400	30,522,100
21	Scope 2 GHG emissions[12] ✓	**186,400**	182,300	187,300
22	Total transportation greenhouse gas emissions *(tonnes CO_2e)*[13] ✓	**119,700**	118,500	101,200
	Land Use and Reclamation[14]			
23	Land use – disturbed *(cumulative hectares)* ✓	**11,800**	11,700	11,600
24	Land use – reclaimed *(cumulative hectares)* ✓	**4,900**	4,900	4,800
25	Land reclamation *(% of former land reclaimed)* ✓	**42**	42	42
26	Land used in mining activities *(hectares)*[15] ✓	**6,900**	6,800	6,800
27	Land used by plants, offices, and equipment *(hectares)*[16] ✓	**3,900**	3,700	3,700
	Environmental Incidents			
28	Total environmental incidents[17] ✓	**12**	15	14
29	Environmental enforcement actions	**1**	0	4
30	Environmental fines *($ thousands)*	**2**	0	0
	Spills[18]			
31	Volume of significant spills *(m^3)* ✓	**19**	463	1,155
32	Volume of significant spills recovered *(m^3)* ✓	**19**	446	520
33	% of spills recovered	**99**	96	45

	Social Performance	2015	2014	2013
	Workplace Practices			
34	Employees	**2,380**	2,786	2,772
35	Number of full-time employees	**2,301**	2,629	2,624
36	Number of part-time employees	**26**	79	87
37	Number of contingent employees	**53**	78	61
38	Employees represented by independent trade union organizations *(%)*(19)	**54**	53	33
39	Voluntary employee turnover rate *(%)*(20) ✓	**5.22**	6.97	7.31
	Diversity			
40	Women in workforce *(%)*(21) ✓	**18**	19	22
41	Women in senior management *(%)*(22) ✓	**25**	35	32
42	Women on Board of Directors *(%)*	**30**	36	27
43	Workforce under age 30 *(%)*	**10**	12	13
44	Workforce between ages 30 and 50 *(%)*	**53**	51	51
45	Workforce over age 50 *(%)*	**38**	37	36
	Health and Safety			
46	Health and safety enforcement actions(23)	**0**	0	0
47	Health and safety fines *($ thousands)*	**0**	0	0
48	Employee fatalities ✓	**0**	0	0
49	Lost time injury (LTI) (absence from work) ✓	**3**	5	3
50	Medical aids (MA) (no absence from work) ✓	**11**	13	12
51	Total injuries to employees ✓	**14**	18	15
52	Employee recordable (LTI & MA) injury frequency rate *(injuries/200,000 hours)*(24) ✓	**0.57**	0.96	0.74
53	Employee disabling (LTI) injury frequency rate *(injuries/200,000 hours)*(25) ✓	**0.12**	0.27	0.15
54	Contractor fatalities ✓	**0**	0	0
55	Lost time injury (LTI) (absence from work) for contractors ✓	**2**	0	0
56	Medical aids (MA) (no absence from work) for contractors ✓	**9**	4	14
57	Total injuries to contractors ✓	**11**	4	14
58	Contractor recordable (LTI & MA) injury frequency rate *(injuries/200,000 hours)*(24) ✓	**1.24**	0.58	1.27
59	Contractor disabling (LTI) injury frequency rate *(injuries/200,000 hours)*(25) ✓	**0.23**	0.00	0.00
	Total IFR (employees and contractors)(24) ✓	**0.75**	0.86	0.93
60	Reportable vehicle incidents	**28**	37	42
	Community Relations			
61	Community investments *($ millions)*(26) ✓	**3.5**	3.6	3.8

✓ *2015 data has been third-party assured to a limited assurance level by Ernst & Young LLP.*
Please see "Discussion and Notes on Numbers" for footnote explanations.

Discussion and Notes on Numbers

TransAlta continually strives to improve the accuracy and coverage of our sustainability performance reporting to stakeholders. We review our processes and controls relating to the measurement and calculation of key sustainability data annually. Several footnotes appear throughout the statistical summary and are intended to provide clarity on specific boundary conditions, changes in methodology, and definitions. For questions or clarity on any key performance indicators, please contact us at **sustainability@transalta.com.**

(1) ISO 14001 and ISO 18001 are the world's most recognized standards for Environmental Management and Health and Safety Management systems. TransAlta has ownership in 69 facilities.

(2) Internal audits conducted against ISO management systems.

(3) Internal audits conducted against regulatory frameworks.

(4) Part of the Alberta Certificate of Recognition audit. Audits only applicable in Alberta.

(5) Air emissions are reported from TransAlta-operated facilities, where we report 100 per cent of emissions despite having a lower percentage of financial ownership in some facilities. Air emissions are expressed in tonnes, except for mercury emissions, which are represented in kilograms. Historic 2013 and 2014 particulate matter emissions were restated in 2015 to account for emissions that were not being captured in our reporting from our Centralia facility.

(6) Emissions intensity data has been aligned with the 'Setting Organizational Boundaries: Operational Control' methodology set out in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. Air emissions, although not greenhouse gas (GHG), are coincidentally aligned with this reporting boundary for consistency. As per the methodology, TransAlta reports emissions on an operation control basis and hence we therefore report 100 per cent of emissions at facilities in which we are the operator. Emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership. Previously, emission intensities were calculated by dividing operational control emissions by financial production volumes (MWh), which we have deemed to be an inaccurate representation of our emission intensity. Historical 2013 and 2014 emission intensities have been restated to align with this approach.

(7) Greenhouse gas emissions are calculated across our fleet, typically in line with carbon regulation where the facility is located, and include emissions from stationary combustion, transportation use, building use, and fugitive emissions. Historical 2014 emission data was restated in 2015 as a result of an incorrect use of an emission factor when calculating CO_2 emissions at our Ottawa facility and incorrect emission factor use when calculating wind and head office natural gas consumption emissions. Historical 2013 emission data was restated to account for incorrect emission factor use when calculating wind and head office natural gas consumption emissions. Changes resulted to approximately a 0.02 per cent adjustment in 2014 and less than 0.01 per cent in 2013. Subtotals, carbon dioxide, methane, and nitrous oxide have been restated to include transportation emissions.

(8) Sulfur hexafluoride emissions from our Australia facilities were revised to align with guidance from the National Greenhouse and Energy Reporting regulation.

(9) Gross CO_2e emissions or gross GHG emissions is the sum of carbon dioxide, methane, nitrous oxide, and sulfur hexafluoride. Coincidentally, the sum of scope 1 and 2 emissions will equate to gross CO_2e emissions or gross GHG emissions.

(10) Emissions intensity data has been aligned with the 'Setting Organizational Boundaries: Operational Control' methodology set out in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. As per the methodology, TransAlta reports emissions on an operation control basis and hence we therefore report 100 per cent of emissions at facilities in which we are the operator. Emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership. Previously, emission intensities were calculated by dividing operational control emissions by financial production volumes (MWh), which we have deemed to be an inaccurate representation of our emission intensity. Historical 2013 and 2014 emission intensities have been restated to align with this approach.

(11) Scope 1 GHG emissions are all direct GHG emissions. For example, coal or gas combusted in one of our plants.

(12) Scope 2 GHG emissions are all indirect GHG emissions. For example, the consumption of purchased electricity, heat, and steam.

(13) Total transportation GHG emissions are reported in order to track our performance in this area. Total transportation GHGs are accounted for in gross emission totals.

(14) Centralia land disturbed and reclamation data has been restated for 2013 and 2014 due to data alignment with reporting to the Office of Surface Mining in Washington State. The change impacted overall disturbed and reclaimed totals. The resulting change increased our total percentage of land reclamation. Land reclaimed includes the percentage of mined land reclaimed at the Whitewood and Highvale coal mines at Wabamun, Alberta, and our surface mine in Centralia, Washington.

(15) Mining land use is total land disturbed minus reclaimed area.

(16) Historical land use data for 2014 was revised to include our Solomon gas facility, which is located in north Western Australia. The restatement was minor, as adding eight hectares, and after rounding no change is evident.

(17) All environmental incidents are reported to an external regulatory agency, which may result in a fine, penalty, or corrective action.

(18) Substances released to the environment include, but are not limited to, ash, glycol, diesel, oils, and other chemicals. Our 2014 environmental spills and spill recovery volumes were restated due to revision of the reporting boundary for spills.

(19) TransAlta acquired SunHills in 2013 and with it over 600 employees, the majority of which are unionized. The value of 33 per cent in 2013 is not inclusive of unionized employees from SunHills as at year-end December 31, 2013. Employee-specific data from SunHills was integrated further in 2014.

(20) The process to determine voluntary turnover has been revised to align with our HR voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any exit initiated by a full-time, part-time, or contingent employee, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover. Historical values for 2013 and 2014 have been revised to align with this approach. In 2015 we began including employees from SunHills in our turnover calculations. SunHills was acquired in 2013 and represents our employees at the Highvale mine, which is adjacent to our Alberta coal operations west of Edmonton.

(21) Our total percentage of women in the workforce declined slightly as a result of corporate restructuring in 2015.

(22) Our total percentage of women in senior management declined as a result of corporate restructuring in 2015. Our pool of Vice-Presidents and Directors was reduced from 70 employees to 23 employees in 2015 and combined into a Managing Director level.

(23) Health and safety incidents resulting in a regulatory enforcement action. Enforcement actions could take the form of a warning letter, fine, or non-financial reprimand or restriction on operations.

(24) The injury frequency rate (IFR) measures work-related medical aid and lost-time injuries per 200,000 hours worked. IFR is calculated using a combination of actual and estimated exposure hours. During the course of the year, all work-related safety incidents are investigated. These investigations may provide new information that would result in an incident being reclassified.

(25) The disabling injury frequency rate is calculated based on the number of injuries requiring absence from work (lost-time incidents) only.

(26) Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.

Ernst & Young Independent Limited Assurance Statement

To the Board of Directors and Management of TransAlta Corporation ("TransAlta").

Our Responsibilities

Our limited assurance engagement has been planned and performed in accordance with the International Standard on Assurance Engagements (ISAE) 3000 "Assurance Engagements Other than Audits or Reviews of Historical Financial Information."

Subject Matter

We have performed a limited assurance engagement on the following quantitative sustainability performance indicators that are presented on pages 189 to 191 of the TransAlta Annual Integrated Report ("the Report") for the year ended December 31, 2015:

- Sulphur dioxide emissions and emission intensity (tonnes, kg/MWh)
- Nitrogen oxide emissions and emission intensity (tonnes, kg/MWh)
- Particulate matter emissions and emission intensity (tonnes, kg/MWh)
- Mercury emissions and emission intensity (kg, mg/MWh)
- Carbon dioxide emissions (tonnes CO_2e)
- Methane emissions (tonnes CO_2e)
- Nitrous oxide emissions (tonnes CO_2e)
- Total transportation greenhouse gas emissions (tonnes CO_2e)
- Gross greenhouse gas emissions and emission intensity (tonnes CO_2e, tonnes CO_2e/GWh)
- Scope 1 GHG emissions (tonnes CO_2e)
- Scope 2 GHG emissions (tonnes CO_2e)
- Land use – Disturbed, reclaimed (cumulative hectares)
- Land reclamation (% of former land reclaimed)
- Land used in mining activities (hectares)
- Land used by plants, offices, and equipment (hectares)
- Total environmental incidents
- Volume of spills (m^3)
- Voluntary employee turnover rate (%)
- Women in the workforce (%)
- Women in senior management (%)
- Employee and contractor fatalities
- Lost-time injuries for employees and contractors (LTI) (absence from work)
- Medical aids (MA) for employees and contractors (no absence from work)
- Total injuries to employees and contractors
- Employee and contractor recordable (LTI & MA) injury frequency rate (injuries/200,000 hours)
- Employee and contractor disabling (LTI) injury frequency rate (injuries/200,000 hours)
- Community investments ($ millions)

Criteria

TransAlta has prepared its specified performance information in accordance with industry standards and, where relevant, internally developed criteria.

TransAlta Management Responsibilities

The Report was prepared by the management of TransAlta, who is responsible for the collection and presentation of the performance indicators, statements, claims in the Report, and the criteria used in determining that the information is appropriate for the purpose of disclosure in the Report. In addition, management is responsible for maintaining adequate records and internal controls that are designed to support the reporting process.

Level of Assurance

Our procedures were designed to obtain a limited level of assurance on which to base our conclusions. The procedures conducted do not provide all the evidence that would be required in a reasonable assurance engagement and, accordingly, we do not express a conclusion conveying a reasonable level of assurance. While we obtained an understanding of management's internal processes when determining the nature and extent of our procedures, our limited assurance engagement was not designed to express a conclusion on internal controls.

Work Performed

In order for us to express a conclusion in relation to the above scope of work, we have sought to answer the following questions for the performance indicators reviewed:

Completeness

- Has TransAlta fairly presented performance information concerning the selected performance indicators with respect to the boundaries and time period defined in the Report?
- Has TransAlta included sustainability performance information from all material entities in its defined boundary for its reporting of the selected performance indicators?
- Has TransAlta accurately collated corporate data r elating to the selected performance indicators from operations-level data?

Accuracy

- Is the data reported for the selected performance indicators sufficiently accurate and detailed for stakeholders to assess TransAlta's performance?

Our assurance procedures at TransAlta's corporate head office included but were not limited to:

- Interviewing selected personnel at Corporate and selected sites to understand the key sustainability issues related to the selected performance data and processes for the collection and accurate reporting of performance information
- Where relevant, obtaining an understanding of the design and implementation of systems and processes for data aggregation and reporting
- Checking key assumptions against the evidence to support the assumptions
- Checking the accuracy of calculations performed, on a test basis, primarily through inquiry, variance analysis, and re-performance of calculations and analytical procedures
- Checking that data and statements had been correctly transcribed from corporate systems and/or supporting evidence into the Report

Limitations of our Work Performed

Our scope of work did not include expressing conclusions in relation to:

- The materiality, completeness, or accuracy of data sets or information relating to areas other than the selected performance data, and any site-specific information
- Information reported outside of the Report
- Management's forward-looking statements
- Any comparisons made by TransAlta against historical data
- The appropriateness of definitions for internally developed criteria

Our Conclusion

Based on our procedures for this limited assurance engagement described in this Report, nothing has come to our attention that causes us to believe that the Subject Matter is not, in all material respects, reported in accordance with the relevant criteria.

Ernst & Young LLP

Ernst & Young LLP
Calgary, Canada

February 17, 2016

Shareholder Information

Annual Meeting
The Annual Meeting of Shareholders will be held at 10:00 a.m. MST, on Friday, April 22, 2016 at Hotel Arts 119 - 12th Avenue SW, Calgary, Alberta.

Transfer Agent
CST Trust Company*
P.O. Box 700 Station "B"
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Exchanges
Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

Ticker Symbols
TransAlta Corporation common shares:
TSX: TA, NYSE: TAC
TransAlta Corporation preferred shares:
TSX: TA.PR.D, TA.PR.F, TA.PR.H, TA.PR.J

* *CST Trust Company has succeeded CIBC Mellon Trust Company as our transfer agent. On Nov. 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 Aug. 30, 2013, at which time CST Trust Company, an affiliate of Canadian Stock Transfer Company Inc., received federal approval to commence business.*

Special Services for Registered Shareholders

Service	Description
Direct deposit for dividend payments	Automatically have dividend payments deposited to your bank account
Account consolidations	Eliminate costly duplicate mailings by consolidating account registrations
Address changes and share transfers	Receive tax slips and dividends without the delays resulting from address and ownership changes

Stock Splits and Share Consolidations

Date	Events
May 8, 1980	Stock split
Feb. 1, 1988	Stock split(1)
Dec. 31, 1992	Reorganization – TransAlta Utilities shares exchanged for TransAlta Corporation shares(2) 1:1

The valuation date value of common shares owned on Dec. 31, 1971, adjusted for stock splits, is $4.54 per share.
(1) The adjusted cost base for shares held on Jan. 31, 1988, was reduced by $0.75 per share following the Feb. 1, 1988 share split.
(2) TransAlta Utilities Corporation became a wholly owned subsidiary of TransAlta Corporation as a result of this reorganization.

Dividend Declaration for Common Shares
Dividends are paid quarterly as determined by the Board. 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, 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.

Common Share Dividends Declared in 2015

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2015	March 2, 2015	Feb. 26, 2015	$0.18
July 1, 2015	June 1, 2015	May 28, 2015	$0.18
Oct. 1, 2015	Sept. 1, 2015	Aug. 28, 2015	$0.18
Jan. 1, 2016	Dec. 1, 2015	Nov. 27, 2015	$0.18

Dividends are paid on the first of the month in January, April, July and October. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Submission of Concerns Regarding Accounting or Auditing Matters
TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Chief Legal and Compliance Officer and Corporate Secretary of the Corporation.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Dec. 10, 2010 to but excluding March 31, 2016.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.15 per share from the date of issue Nov. 29, 2011 to but excluding June 30, 2017.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.25 per share from the date of issue Aug. 10, 2012 to but excluding Sept. 30, 2017.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.325 per share from the date of issue Aug. 15, 2014 to but excluding Sept. 30, 2019.

Preferred Share Dividends Declared in 2015

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2015	March 2, 2015	Feb. 26, 2015	$0.2875
June 30, 2015	June 1, 2015	May 28, 2015	$0.2875
Sept. 30, 2015	Sept. 1, 2015	Aug. 28, 2015	$0.2875
Dec. 31, 2015	Dec. 1, 2015	Nov. 27, 2015	$0.2875

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2015	March 2, 2015	Feb. 26, 2015	$0.2875
June 30, 2015	June 1, 2015	May 28, 2015	$0.2875
Sept. 30, 2015	Sept. 1, 2015	Aug. 28, 2015	$0.2875
Dec. 31, 2015	Dec. 1, 2015	Nov. 27, 2015	$0.2875

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2015	March 2, 2015	Feb. 26, 2015	$0.3125
June 30, 2015	June 1, 2015	May 28, 2015	$0.3125
Sept. 30, 2015	Sept. 1, 2015	Aug. 28, 2015	$0.3125
Dec. 31, 2015	Dec. 1, 2015	Nov. 27, 2015	$0.3125

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2015	March 2, 2015	Feb. 26, 2015	$0.33125
June 30, 2015	June 1, 2015	May 28, 2015	$0.33125
Sept. 30, 2015	Sept. 1, 2015	Aug. 28, 2015	$0.33125
Dec. 31, 2015	Dec. 1, 2015	Nov. 27, 2015	$0.33125

Dividends are paid on the last day of the month in March, June, September, and December. When a dividend payment date falls on a weekend or holiday, the payment is made on the following business day. Only dividend payments that have been approved by the Board of Directors are included in this table.

Voting Rights

Common shareholders receive one vote for each common share held.

Additional Information

Requests can be directed to:

Investor Relations
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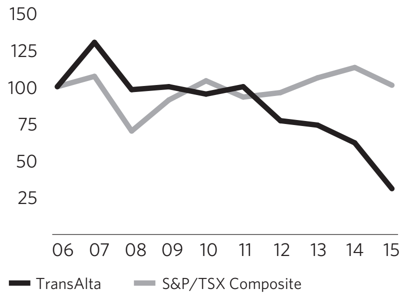
Shareholder Highlights



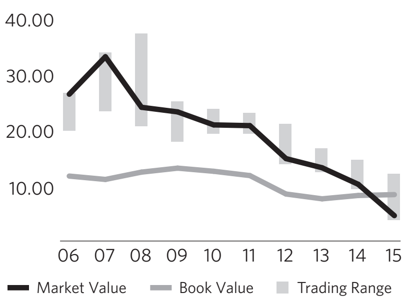
Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*

	06	07	08	09	10	11	12	13	14	15
TransAlta	100	130	98	100	95	100	77	74	62	31
S&P/TSX Composite	100	107	70	91	104	93	96	106	113	101

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2006 would be worth today, assuming the reinvestment of all dividends.

Source: Thomson Financial



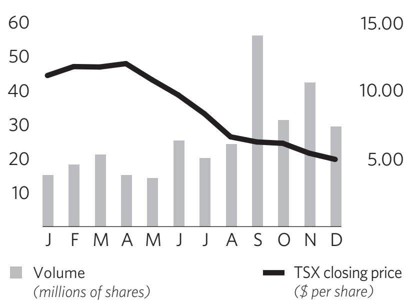
Ten-Year Trading Range and Market Value vs. Book Value

Year ended Dec. 31 *($ per share)*

	06	07	08	09	10	11	12	13	14	15
Market Value	26.64	33.35	24.30	23.48	21.15	21.02	15.12	13.48	10.52	4.91
Book Value	11.99	11.39	12.70	13.41	12.85	12.08	8.78	7.92	8.52	8.52

Amounts presented or included in calculations prior to 2010 represent Canadian Generally Accepted Accounting Principles (GAAP) figures and have not been restated under International Financial Reporting Standards (IFRS).

Source: Thomson Financial and TransAlta

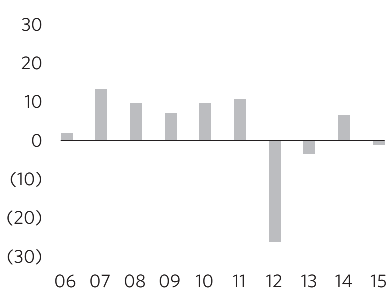


Monthly Volume and Market Prices

(2015)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	15	18	21	15	14	25	20	24	56	31	42	29
TSX closing price	11.12	11.78	11.75	12.00	10.80	9.68	8.29	6.58	6.20	6.10	5.37	4.91

Source: Thomson Financial



Return on Common Shareholders' Equity

(%)

	06	07	08	09	10	11	12	13	14	15
ROE	1.8	13.1	9.4	6.9	9.6	10.6	(25.9)	(3.2)	6.3	(1.2)

Amounts presented or included in calculations prior to 2010 represent GAAP figures and have not been restated under IFRS.

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 manage our 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.

Source: TransAlta

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

TransAlta's Corporate Governance Guidelines, Board Charter, Committee Charters, position descriptions for the Chair, Committee Chair, President & CEO, and codes of business conduct and ethics are available on our website at www.transalta.com. Also available on our website is a summary of the significant ways in which TransAlta's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards. Currently there are no differences between our governance practices and those of the New York Stock Exchange.

Ethics Helpline

The Board of Directors has established an anonymous and confidential internet portal, email address and toll-free telephone number for employees, contractors, shareholders and other stakeholders to contact with respect to accounting irregularities, ethical violations or any other matters they wish to bring to the attention of the Board.

The Ethics Helpline phone number is **1.855.374.3801 (U.S./Canada)**
and **1.800.339276 (Australia)**
Internet portal: **transalta.ethicspoint.com**
E-mail: **TA_ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to
corporate_secretary@transalta.com

TransAlta Corporate Officers

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

Brett M. Gellner
Chief Investment Officer

Dawn E. de Lima
Chief Administrative Officer

John H. Kousinioris
Chief Legal and Compliance Officer
and Corporate Secretary

Cynthia Johnston
Executive Vice-President, Gas,
Renewables & Operations Services

Wayne A. Collins
Executive Vice-President,
Coal and Mining Operations

Jennifer M. Pierce
Senior Vice-President,
Trading & Marketing

Todd J. Stack
Managing Director and Treasurer

Ben Park
Managing Director,
Corporate Controller

Scott Jeffers
Assistant Corporate Secretary
and Legal Counsel

Glossary of Key Terms

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

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

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

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.

Derate
To lower the rated electrical capability of a power generating facility or unit.

Expected Capacity
Plant capacity after consideration of station service use, planned outages, forced and maintenance outages, and derates.

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.

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 Btu.

Gigawatt (GW)
A measure of electric power equal to 1,000 megawatts.

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

Greenhouse Gas (GHG)
A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, and perfluorocarbons.

Heat Rate
A measure of conversion, expressed as Btu/MWh, of the amount of thermal energy required to generate electrical energy.

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

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

Merchant Assets
TransAlta uses the term merchant to describe assets that have contracts with terms of less than five years. Given our low-to-moderate risk profile, TransAlta contracts a significant portion of its merchant capability through short- and medium-term contracts.

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

Renewable Power
Power generated from renewable terrestrial mechanisms including wind, geothermal, solar, and biomass with regeneration.

Reserve Margin
An indication of a market's capacity to meet unusual demand or deal with unforeseen outages/shutdowns of generating capacity.

Spark Spread
A measure of gross margin per MW (sales price less cost of natural gas).

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

Turbine
A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction or a mixture of the two.

Turnaround
Periodic planned shutdown of a generating unit for major maintenance and repairs. Duration is normally in weeks. The time is measured from unit shutdown to putting the unit back on line.

Unplanned Outage
The shutdown of a generating unit due to an unanticipated breakdown.

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

Value at Risk (VaR)
A measure used to manage exposure to market risk from commodity risk management activities.

This report was printed in Canada. The paper, paper mills, and printer are all Forest Stewardship Council certified, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests.

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