TransAlta

Balance Wins

TransAlta Corporation

2016 Annual Integrated Report

Letter to Shareholders

2016 was a remarkable, challenging and productive year for TransAlta. With the parameters of our company's new carbon obligations defined, we can turn our attention to our strategic vision for the future of the company: becoming Canada's leading clean power company. We believe the achievements of 2016 have restored value to TransAlta in the market and the execution of our strategy will continue to do so.

Throughout 2016, our actions were guided by three strategic themes: Execution Advantage, Balance Wins and History Repeats.

Execution Advantage

The execution of a mutually acceptable coal transition agreement with the Government of Alberta was the culmination of our top priority for 2016. With that overhang relieved, investors once again can see TransAlta as a leading power generator with competitive assets in strategic energy markets.

Our experienced, skilled and hard-working teams accomplished the following:

- We signed an Off-Coal Agreement with the Government of Alberta to eliminate coal-fired emissions from our Keephills 3, Genesee 3 and Sheerness generating plants by 2030. This agreement entitles the company to 14 annual payments of $37.4 million, starting in 2017.

- We signed a Memorandum of Understanding (MOU) with the Government of Alberta that outlines our future co-operative work to:

  1. Enable our Alberta coal plants to transition to natural gas and extend their useful lives;

  2. Realize additional value in our hydro and wind assets through greenhouse gas offset credits;

  3. Begin to develop our Brazeau Pumped Storage project, one of the leading hydro power projects on the drawing board in Canada; and

  4. Develop a capacity market in Alberta that ensures both current and new electricity generators will have a level economic playing field to build, buy and sell electricity.

- Financially, we met our 2016 goals by delivering comparable EBITDA of $1.15 billion, comparable funds from operations of $763 million and comparable free cash flow of $299 million. And we did this in one of the lowest commodity price cycles ever experienced in the Alberta market.

- We raised approximately $360 million of project debt and now have access to $1.7 billion in liquidity. This will be used to settle the US$400 million of senior notes with maturities coming due in June 2017. We continue to make progress on our goal to reposition our capital structure and strengthen the balance sheet. We maintained our investment grade credit ratings with S&P, Fitch and DBRS.

- Operationally, we delivered fleet availability of 89%, just ahead of 2015. Our Injury Frequency Rate of 0.85 was the second-best in our company's history, but unfortunately higher than our record of 0.75 set in 2015. Safety remains a top priority.

- We advanced construction of our South Hedland 150 megawatt (MW) combined cycle gas-fired power plant in Port Hedland, Australia, which we expect to commission in mid-2017.

- We executed a new contract with the Ontario Independent Electricity System Operator for the 108 MW Mississauga cogeneration facility. The new contract will provide us with fixed monthly payments until the end of 2018, with no delivery obligations.

- We won an arbitration upholding TransAlta's force majeure claim at Keephills, which allowed us to reverse the approximately $95 million provision.

We are proud of our accomplishments in 2016. We enter 2017 with initiatives to push even harder on safety, availability and costs. We want our customers to continue to receive the highest value for their money. We know that standing still leads to complacency, and that managing change, disruption and innovation are necessary to succeed in meeting the needs of our customers and investors.

Balance Wins

Our second strategic theme was "Balance Wins." The 2015 Alberta Climate Leadership Plan set out challenging goals, including the phase-out of coal by 2030, paying a $30 per tonne carbon tax starting in 2018 and adding 5,000 MW of renewables over the next 13 years. To put this renewables growth target in context, it has taken approximately 105 years to develop Alberta's 16,400 MW system of power generation.

Last year, the Canadian federal government also proposed a framework in which each province is expected to implement a greenhouse gas policy equivalent to a carbon price of $50 per tonne by 2022.

Our challenge was to create a transition plan that would restore value in TransAlta's existing coal-fired plants. This meant the need to devise solutions that would maintain Alberta's competitiveness and keep prices reasonable and affordable for consumers and our customers, while preserving positive economics for the company.

The combination of the Off-Coal Agreement, the MOU, and the Province's move to a capacity market struck the balance needed to move forward constructively. Our next step is to work with the Government of Alberta to create the rules and systems that will support a functioning, resilient capacity market. This will be complicated and will take time.

Our expectation is that by the end of 2020, when the current coal and hydro Power Purchase Arrangements (PPAs) roll off, we will transition to a new market that will price capacity and energy payments separately for our assets. In this interim period, our current PPAs will continue to provide a secure source of cash flows from our Alberta assets.

We expect that all our assets will continue to be competitive in this new market. We also expect that new regulations on coal-to-gas conversions will permit us to extend the useful lives of our existing coal assets. This is necessary to maintain our cash flow and to keep prices affordable for consumers in the new capacity-based regime.

The best news is that the continued cash flow from our generating assets will provide investors with a clear line of sight as to how we can refinance debt during this transition to a new market structure. This sustains investor confidence.

There is more work ahead as we advocate for the necessary rules to permit and regulate coal-to-gas conversions and operate in a new capacity market. We must ensure we can economically transition our plants, and receive fair returns on the capital invested on behalf of investors.

Our "Balance Wins" strategy will continue to guide us. We know that what works for customers in the long run also protects investors.

History Repeats

Our journey to become the largest electric power generator in Alberta started in 1911, when Calgary Power's entrepreneurs built the first hydro plant on the Bow River. Today, these original hydro plants continue to operate and support Alberta's power system.

In 1956, TransAlta commissioned its first large, centralized coal-fired generating plants, and in the 1980s added natural gas and cogeneration plants. In the new millennium, we built and acquired wind power, and in 2015 we invested in our first solar plant. As a result, TransAlta today is a 105-year old company with a diversified fleet of more than 70 power plants across Canada, the United States and Australia.

“ Our Balance Wins strategy will continue to guide us. We know that what works for customers in the long run also protects investors.

Many of our Alberta assets were developed and paid for under a regulated power regime. Since 2000, some plants, such as Genesee 3 and Keephills 3, were commissioned under a deregulated power regime. A price on carbon was not included in either system. Going forward, electricity pricing will continue to be deregulated, but will now include a new cost input: a price on carbon.

Customers will always need affordable and reliable power. Our job now is to make power affordable by finding ways to mitigate expensive carbon taxes.

Our non-emitting hydro assets are even more valuable in this system. Investing in projects such as our Brazeau Pumped Storage hydro expansion will be good for both investors and customers. This 600 MW to 900 MW project will act like a storage battery to support intermittent renewable power.

Our journey back to our historic roots in hydro and the repurposing of our existing coal plants to burn lower-emitting, on-demand natural gas are both important. These actions ensure that TransAlta will remain an important player in the Alberta power market.

Looking Ahead

Today, TransAlta is a multi-regional power company that generates baseload electricity with low-cost coal as part of its competitive advantage. We have the asset base and the optionality to remain strong in our regions. As we strengthen our balance sheet, we will have the additional financial flexibility to make sound and profitable investments for the future. Our goal to be Canada’s leading clean power company remains front and center in all our decisions.

In 2017, our three themes will continue to guide us. We will add a fourth theme: “Accelerating Competitiveness.” We will accelerate investments to create new competitive pricing and environmental advantages that will permit our company to excel in a world in which carbon will be expensive and customers continue to want affordable and clean power.

Our specific goals for 2017 are to:

- Execute on all our financial and operational goals, using the cash generated to both reduce debt and invest for the future. Our 2017 Financial Outlook, found on page M60 of this report, outlines these goals;

- Commission the South Hedland power station, which will contribute new cash flows for investors in TransAlta and in TransAlta Renewables;

- Work with the Government of Alberta to design a path that will advance our investment in the Brazeau Pumped Storage project;

- Work to help design a capacity market that will be fair to existing generators, keep prices affordable for consumers, and incent new investment;

- Establish the detailed terms and conditions to extend the useful lives of our coal fleet by converting them to gas fuel and preparing them for the new capacity market;

- Pursue new long-term contracts on proposed wind projects in Saskatchewan and Alberta;

- Evolve and implement a more competitive business model and cost structure that works for more distributed gas and renewable plants across several regions.

There is a lot to do and we are already moving to execute our plans to achieve each of these goals.

The hard work of 2016 demonstrates that TransAlta can and will successfully transition into the evolving clean power era. It also lays the foundation for continued cash flow from existing assets that will support the investments for what we do best – generate affordable and reliable power for all our customers. 2016 was a transformational year and we look forward to the future.

Thank you.

Dawn L. Farrell
President and Chief Executive Officer

Ambassador Gordon D. Giffin
Chair of the Board of Directors

March 2, 2017

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

Forward-Looking Statements

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

In particular, this MD&A contains forward-looking statements pertaining to our business and anticipated future financial performance; our success in executing on our growth projects; the timing of the construction and commissioning of projects under development, including major projects such as the South Hedland power project and the Sundance 7 project, and their attendant costs; spending on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spending, and maintenance, and the variability of those costs; expected decommissioning costs; the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses, expectations relating to the dispositions of assets and the completion of sale transactions including the disposition of our interest in the Wintering Hills wind facility; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2017 comparable earnings before interest, taxes, depreciation, and amortization ("EBITDA"), comparable funds from operations ("FFO"), comparable free cash flow ("FCF"), and expected sustaining capital expenditures); expectations in respect of financial ratios and targets and the timing associated with meeting such targets (including comparable FFO before interest to adjusted interest coverage, adjusted comparable FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); the Corporation's plans and strategies relating to repositioning its capital structure and strengthening its balance sheet and the debt reductions that are expected to occur in 2017 and beyond; expected governmental regulatory regimes and legislation (including the Government of Alberta's Climate Leadership Plan) and proposed regulations to discontinue over time the use of technologies that our coal-fired plants currently utilize, and their expected impact on TransAlta and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected results and impact of the recently signed Off-Coal Agreement ("OCA") and Memorandum of Understanding ("MOU") with the Government of Alberta on our business and financial performance; the outcome of discussions with the Government of Alberta in relation to potential opportunities for investment in renewable and gas-fired generation; our comparative advantages over our competitors; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity in both the short term and long term, and the resulting impact on electricity prices; our share of offer control in the Province of Alberta after the expiry of the Power Purchase Arrangements ("PPAs") at the end of 2020; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; expectations regarding the role different energy sources will play in meeting future energy needs, including the impact of the anticipated elimination of current excess system capacity and future growth in Alberta driven by the retirement of coal units over the next 15 years; expected financing of our capital expenditures; the anticipated financial impact of increased carbon price (including under the existing Specified Gas Emitters Regulation) ("SGER") in Alberta; expectations in respect of our environmental initiatives; our trading strategies and the risk involved in these strategies; estimates of future tax rates, future tax expense, and the adequacy of tax provisions; accounting estimates; anticipated growth rates in our markets; our expectations regarding the outcome of existing or potential legal and contractual claims, regulatory investigations, and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar, the Australian dollar, and other currencies in which we do business; the monitoring of our exposure to liquidity risk; expectations regarding the impact of the slowdown in the oil and gas sector; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; expected cost savings following the implementation of our efficiency and productivity initiatives; the estimated contribution of Energy Marketing activities to gross margin;

expectations relating to the performance of TransAlta Renewables Inc.'s ("TransAlta Renewables") assets; expectations regarding our continued ownership of common shares of TransAlta Renewables; the refinancing our upcoming debt maturities over the next two years by raising $700 million to $900 million of debt secured by contracted cash flows; expectations regarding our de-leveraging strategy, including applying a portion of our free cash flow over the next four years to reduce debt expectations in respect of our community initiatives; impacts of future IFRS standards; and amendments or interpretations by accounting standard setters prior to initial adoption of those standards.

Factors that may adversely impact our forward-looking statements include risks relating to: fluctuations in market prices and the availability of fuel supplies required to generate electricity; our ability to contract our generation for prices that will provide expected returns; the regulatory and political environments in the jurisdictions in which we operate; increasingly stringent environmental requirements and changes in, or liabilities under, these requirements; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, or wind required to operate our facilities; natural or man-made disasters; the threat of terrorism and cyberattacks and our ability to manage such attacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective or timely manner; commodity risk management; industry risk and competition; fluctuations in the value of foreign currencies and foreign political risks; the need for additional financing and the ability to access financing at a reasonable cost; our ability to fund our growth projects; our ability to maintain our investment grade credit ratings; structural subordination of securities; counterparty credit risk; our ability to recover our losses through our insurance coverage; our provision for income taxes; legal, regulatory, and contractual proceedings involving the Corporation; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; development projects and acquisitions, including delays or changes in costs in the construction of the South Hedland power project; and the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives.

The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and under the heading "Risk Factors" in our 2017 Annual Information Form.

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

Additional IFRS Measures and Non-IFRS Measures

An additional IFRS measure is a line item, heading, or subtotal that is relevant to an understanding of the financial statements but is not a minimum line item mandated under IFRS, or the presentation of a financial measure that is relevant to an understanding of the financial statements but is not presented elsewhere in the financial statements. We have included line items entitled gross margin and operating income (loss) in our Consolidated Statements of Earnings (Loss) for the years ended Dec. 31, 2016, 2015, and 2014. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We evaluate our performance and the performance of our business segments using a variety of measures. Certain of the financial measures discussed in this MD&A are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures may not be comparable to similar measures presented by other issuers and should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. See the Comparable Funds from Operations and Comparable Free Cash Flow, Discussion of Segmented Comparable Results, and Earnings on a Comparable Basis sections of this MD&A for additional information.

Business Model

Our Business

We are one of Canada's largest publicly traded power generators with over 105 years of operating experience. We own, operate, and manage a highly contracted and geographically diversified portfolio of assets representing nearly 9,000 MW[(1)] of net generating capacity and use a broad range of generation fuels that include coal, natural gas, water, sun, and wind. We are Canada's largest generator of wind power and the largest generator of renewable energy in Alberta. Our energy marketing operations maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions.

Vision and Values

Our vision is to be a leading clean energy company, using our expertise, scale, and diversified fuel mix to capitalize on opportunities in our core markets and growing in areas where our competitive advantages can be employed. Our values are grounded in accountability, integrity, safety, respect for people, innovation and loyalty which together create a strong corporate culture and allow all of our people to work on a common ground and understanding. These values are at the heart of our success.

Strategy for Value Creation

Our goals are to deliver solid returns by developing and operating assets in our three regions and among five fuel types. By 2030, our fleet will be fully transitioned from coal to natural gas and renewables. We maximize value by contracting assets, achieving strong availability, and aiming for first-quartile costs. Our Energy Marketing group adds value to merchant assets through optimization. We develop new greenfield projects and undertake merger and acquisition activities to ensure strategic growth of cash flows over the long term. The transition from coal to natural gas and renewables provides significant opportunity for future growth. In 2013, we launched TransAlta Renewables, our sponsored vehicle to own contracted gas and renewable assets.

(1) We measure capacity as net maximum capacity (see Glossary of Key Terms for definition of this and other key terms), which is consistent with industry standards. Capacity figures represent capacity owned and in operation unless otherwise stated, and reflect the basis of consolidation of underlying assets.

Highlights
Consolidated Financial Highlights

Year ended Dec. 31	2016	2015	2014
Revenues	2,397	2,267	2,623
Comparable EBITDA[1]	1,145	945	1,036
Net earnings (loss) attributable to common shareholders	117	(24)	141
Comparable net earnings (loss) attributable to common shareholders[1]	34	(48)	68
Comparable FFO[1]	763	740	762
Cash flow from operating activities	744	432	796
Comparable FCF[1]	299	315	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.41	(0.09)	0.52
Comparable net earnings (loss) per share[1]	0.12	(0.17)	0.25
Comparable FFO per share[1]	2.65	2.64	2.79
Comparable FCF per share[1]	1.04	1.13	1.03
Dividends declared per common share	0.20	0.72	0.72

As at Dec. 31	2016	2015	2014
Total assets	10,996	10,947	9,833
Total debt[2]	4,056	4,441	4,013
Total long-term liabilities	5,116	5,704	4,504

In 2016, comparable EBITDA increased by $200 million to $1,145 million compared to 2015, with all segments other than U.S. Coal delivering improved results over last year. The improved results throughout the year are a result of positive contributions from renewable assets acquired in the second half of 2015, solid performance from our gas and renewables portfolios, cost reduction initiatives across the fleet implemented in 2015, and the reversal of the $80 million provision relating to our Keephills 1 outage in 2013. Our highly contracted profile and hedging strategy mitigated the impact of lower prices during the year. The decreased contribution from U.S. Coal is attributable to unfavourable market conditions in the Pacific Northwest. Last year's comparable EBITDA was impacted by a $59 million increase in our provision relating to the Keephills 1 outage in 2013.

Comparable FFO increased by $23 million to $763 million. The increase was lower than the increase in comparable EBITDA, primarily due to the non-cash impact of the provision relating to our Keephills 1 outage, which was approximately $139 million of the change in comparable EBITDA.

Reported net earnings attributable to common shareholders was $117 million ($0.41 net earnings per share) compared to a net loss of $24 million ($0.09 net loss per share) in 2015. Comparable net earnings attributable to common shareholders was $34 million ($0.12 net earnings per share), up from a comparable net loss of $48 million ($0.17 net loss per share) in 2015. The improvements year-over-year primarily relate to contributions from assets we acquired in 2015, solid performance from the renewable asset portfolio, and cost reduction initiatives. The Keephills 1 outage provision reversal also favourably impacted 2016 net earnings. Our reported net earnings attributable to common shareholders in 2016 was impacted positively by the Mississauga cogeneration recontracting ($48 million[3]) and negatively by the Wintering Hills wind facility impairment ($21 million[3]). Changes in the fair value of de-designated and economic hedges at U.S. Coal also had a negative impact on our reported net earnings of $17 million[3,4] in 2016 (2015 – $38 million[3,4]).

(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow and Earnings on a Comparable Basis sections of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) Total debt includes current portion, amounts due under credit facilities, long-term debt, tax equity, and finance lease obligations net of cash.

(3) Net of related income tax expense.

(4) Hedge accounting could not be applied to certain contracts, and accordingly, the mark-to-market on these contracts impacted reported earnings. The impacts of these mark-to-market fluctuations have been removed from revenues to arrive at comparable results, which reflect the economic nature of these contracts.

2015's reported net loss also included the gain on the Poplar Creek restructuring ($192 million[1]), the cost of the settlement with the Market Surveillance Administrator (the "MSA") ($55 million[1]), and a $95 million income tax expense related to an internal reorganization. These items are not included in our comparable net earnings.

The decrease of $385 million in total debt, net of cash, is primarily due to repayment of debt using the proceeds received from the sale to TransAlta Renewables of economic interests in the Canadian Assets (as defined below) completed in January 2016, free cash flows generated by the business, and the strengthening of the Canadian dollar.

Significant Events

At the beginning of the year we had three strategic objectives: first, work with the Government of Alberta to develop a plan that would facilitate our transition from coal to natural gas and renewables; second, continue to improve our financial condition and flexibility by reducing our total outstanding corporate debt and better aligning our debt maturities with the life of our assets; and third, commit ourselves to achieving our operational goals (health and safety, equipment availability, and environment). We made significant progress on our strategic objectives in 2016. Our results for the year demonstrate our financial and operating stability. Specifically, we:

- Entered into an OCA with the Government of Alberta (the "Government") for the cessation of coal-fired emissions at our Alberta coal facilities. Under the terms of the OCA, we will receive transition payments of approximately $37.4 million (our net share) from 2017 to 2030 for a total amount of approximately $524 million.
- Entered into an MOU with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market.
- Signed a new contract for our Mississauga cogeneration facility effective Jan. 1, 2017, with Ontario's Independent Electricity System Operator ("IESO") and terminated our existing contract early. The new contract, which expires in December 2018, provides us with monthly payments totalling approximately $209 million over the term of the contract with no delivery obligations. The new contract will allow us to reduce operational costs for this facility while retaining flexibility to operate the facility should economic conditions permit.
- Completed the sale to TransAlta Renewables of an economic interest in the Sarnia cogeneration facility and two renewable energy facilities (collectively, the "Canadian Assets") for aggregate proceeds valued at $540 million. Cash proceeds of this transaction were $173 million. We also received 15.6 million common shares of TransAlta Renewables and a $215 million convertible debenture. Proceeds were used to reduce TransAlta's indebtedness. In November 2016, the economic interest was converted to direct ownership of the Canadian Assets by TransAlta Renewables.
- Repositioned our capital structure through two non-recourse bond issuances in 2016, through our subsidiaries, New Richmond Wind L.P. and TAPC Holdings L.P., in the amounts of $159 million and $202.5 million, respectively. These financings have aligned debt maturities with the contracted cash flows of the underlying assets.
- Announced the sale of our 51 per cent interest in the 88 MW Wintering Hills merchant wind facility, located in Alberta, for approximately $61 million in early 2017. The sale provides us with near-term liquidity, increases our financial flexibility, and reduces our merchant exposure in Alberta.
- Continued to advance the construction of the South Hedland power project. We expect the project to be delivered on schedule and on budget in mid-2017.
- Announced a reduction of our dividend to $0.16 per common share on an annualized basis from $0.72 previously. As a result, our annual dividend is approximately $46 million, down from $205 million, thereby increasing our financial flexibility.

These actions, coupled with our solid financial performance in 2016, are expected to build the financial capacity and flexibility to address upcoming debt maturities and capitalize on growth opportunities in gas-fired and renewable generation that are expected to arise as Alberta transitions from its reliance on coal-fired generation to cleaner sources of power generation.

(1) Net of related income tax expense.

Reconciliation of Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Comparable Funds from Operations and Comparable Free Cash Flow

Comparable FFO is an important metric as it provides a proxy for the amount of cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends more readily in comparison with results from prior periods. Comparable FCF is an important metric as it represents the amount of cash generated by our business, before changes in working capital, that is available to invest in growth initiatives, make scheduled principal repayments on debt, repay maturing debt, pay common share dividends, or repurchase common shares. Changes in working capital are excluded so as to not distort comparable FFO and comparable FCF with changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and the timing of capital projects. Comparable FFO per share and comparable FCF per share are calculated using the weighted average number of common shares outstanding during the period.

The table below reconciles our cash flow from operating activities to our comparable FFO.

Year ended Dec. 31	**2016**	2015	2014
Cash flow from operating activities	**744**	432	796
Change in non-cash operating working capital balances	**(73)**	242	(73)
Cash flow from operations before changes in working capital	**671**	674	723
Adjustments			
MSA settlement payment and California claim	**25**	31	33
Decrease in finance lease receivable	**57**	23	3
Restructuring costs	**4**	19	-
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	**-**	(9)	1
Other	**6**	2	2
Comparable FFO	**763**	740	762
Deduct:			
Sustaining capital	**(272)**	(305)	(361)
Insurance recoveries of sustaining capital expenditures	**1**	25	4
Dividends paid on preferred shares	**(42)**	(46)	(41)
Distributions paid to subsidiaries' non-controlling interests	**(151)**	(99)	(84)
Comparable FCF	**299**	315	280
Weighted average number of common shares outstanding in the year	**288**	280	273
Comparable FFO per share	**2.65**	2.64	2.79
Comparable FCF per share	**1.04**	1.13	1.03

Reconciliation of Comparable EBITDA and Comparable Net Earnings

Comparable EBITDA is a widely adopted valuation metric and an important metric for management that represents our core business profitability. Interest, taxes, and depreciation and amortization are not included, as differences in accounting, treatments may distort our core business results. A reconciliation of reported results to comparable results for the year ended Dec. 31, 2016, is as follows:

Year ended Dec. 31	2016			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,397	123 (1, 2)	26 (5)	2,546
Fuel and purchased power	963	(65) (3)	(14) (9)	884
Gross margin	1,434	188	40	1,662
Operations, maintenance, and administration	489	-	-	489
Asset impairment	28	-	(28) (8)	-
Restructuring	1	-	(1) (10)	-
Taxes, other than income taxes	31	-	-	31
Net other operating (income) losses	(194)	-	191 (9)	(3)
EBITDA	1,079	188	(122)	1,145
Depreciation and amortization	601	122 (2, 3, 4)	(46) (9)	677
Operating income	478	66	(76)	468
Finance lease income	66	(66) (1)	-	-
Foreign exchange loss	(5)	-	(3) (17)	(8)
Gain on sale of assets	4	-	(4) (15)	-
Earnings (loss) before interest and taxes	543	-	(83)	460
Net interest expense	229	-	-	229
Income tax expense	38	-	4 (18, 19, 20, 21)	42
Net earnings	276	-	(87)	189
Non-controlling interests	107	-	(4) (23)	103
Net earnings (loss) attributable to TransAlta shareholders	169	-	(83)	86
Preferred share dividends	52	-	-	52
Net earnings (loss) attributable to common shareholders	117	-	(83)	34
Weighted average number of common shares outstanding in the year	288			288
Net earnings (loss) per share attributable to common shareholders	0.41			0.12

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

Year ended Dec. 31	2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,267	81 (1, 2)	60 (5)	2,408
Fuel and purchased power	1,008	(62) (3)	-	946
Gross margin	1,259	143	60	1,462
Operations, maintenance, and administration	492	-	9 (6)	501
Asset impairment reversals	(2)	-	2 (8)	-
Restructuring	22	-	(22) (10)	-
Taxes, other than income taxes	29	-	-	29
Net other operating (income) losses	25	-	(38) (7, 11)	(13)
EBITDA	693	143	109	945
Depreciation and amortization	545	85 (2, 3, 4)	-	630
Operating income	148	58	109	315
Finance lease income	58	(58) (1)	-	-
Foreign exchange gain	4	-	8 (17)	12
Gain on sale of assets	262	-	(262) (12)	-
Earnings (loss) before interest and taxes	472	-	(145)	327
Net interest expense	251	-	-	251
Income tax expense	105	-	(107) (18,19,20,21)	(2)
Net earnings	116	-	(38)	78
Non-controlling interests	94	-	(14) (23)	80
Net earnings (loss) attributable to TransAlta shareholders	22	-	(24)	(2)
Preferred share dividends	46	-	-	46
Net earnings (loss) attributable to common shareholders	(24)	-	(24)	(48)
Weighted average number of common shares outstanding in the year	280			280
Net loss per share attributable to common shareholders	(0.09)			(0.17)

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

Year ended Dec. 31	2014			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	2,623	52 [1, 2]	(54) [5]	2,621
Fuel and purchased power	1,092	(56) [3]	-	1,036
Gross margin	1,531	108	(54)	1,585
Operations, maintenance, and administration	542	-	(6) [6, 13]	536
Asset impairment reversal	(6)	-	6 [8]	-
Taxes, other than income taxes	29	-	-	29
Gain on sale of assets	-	(1) [4]	-	(1)
Net other operating (income) losses	(14)	-	(1) [7, 14]	(15)
EBITDA	980	109	(53)	1,036
Depreciation and amortization	538	60 [2, 3, 4]	-	598
Operating income	442	49	(53)	438
Finance lease income	49	(49) [1]	-	-
Foreign exchange gain	-	-	4 [16]	4
Gain on sale of assets	2	-	(2) [15]	-
Earnings before interest and taxes	493	-	(51)	442
Net interest expense	254	-	-	254
Income tax expense	7	-	23 [18, 20, 22]	30
Net earnings	232	-	(74)	158
Non-controlling interests	50	-	(1) [23]	49
Net earnings attributable to TransAlta shareholders	182	-	(73)	109
Preferred share dividends	41	-	-	41
Net earnings (loss) attributable to common shareholders	141	-	(73)	68
Weighted average number of common shares outstanding in the year	273			273
Net earnings per share attributable to common shareholders	0.52			0.25

The adjustments made to calculate comparable earnings for the years ended Dec. 31, 2016, 2015 and 2014 are as follows. References are to the previous reconciliation tables.

Year ended Dec. 31				2016	2015	2014
Reference number	Adjustment	Segment	Financial Statement line item			
Reclassifications:						
1	Finance lease income used as a proxy for operating revenue	Australian Gas	Revenues	**52**	49	42
		Canadian Gas	Revenues	**14**	9	7
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	Revenues	**54**	23	4
		Australian Gas	Revenues	**3**	-	(1)
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	Fuel and purchased power	**65**	62	56
4	Reclassification of comparable gain on sale of property, plant, and equipment that is included in depreciation	Canadian Coal	Gain on sale of assets	**-**	-	1
Adjustments (increasing (decreasing) earnings to arrive at comparable results):						
5	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	Revenues	**26**	60	(54)
6	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	OM&A	**-**	(9)	1
7	Non-comparable portion of insurance recovery received	Hydro	Net other operating (income) losses	**-**	(18)	(4)
8	Asset impairment charges (reversals)	U.S. Coal	Asset impairment (reversals)	**-**	(2)	(5)
		Canadian Gas	Asset impairment (reversals)	**-**	-	(1)
		Wind and Solar	Asset impairment (reversals)	**28**	-	-
9	Mississauga recontracting[(1)]	Canadian Gas	Net other operating (income) losses	**(131)**	-	-
10	Restructuring expense	Canadian Coal	Restructuring	**-**	11	-
		U.S. Coal	Restructuring	**-**	1	-
		Canadian Gas	Restructuring	**-**	1	-
		Hydro	Restructuring	**-**	-	-
		Energy Marketing	Restructuring	**-**	3	-
		Corporate	Restructuring	**1**	6	-
11	MSA settlement	Energy Marketing	Net other operating (income) losses	**-**	56	-
12	Gain on Poplar Creek contract restructuring	Canadian Gas	Gain on sale of assets	**-**	(262)	-
13	Costs related to TAMA Transmission bid	Corporate	OM&A	**-**	-	5
14	California claim	Energy Marketing	Net other operating (income) losses	**-**	-	5
15	Non-comparable gain on sale of assets	Equity Investments	Gain on sale of assets	**-**	-	(2)
		Corporate	Gain on sale of assets	**(4)**	-	-
16	Foreign exchange on California claim	Unassigned	Foreign exchange gain (loss)	**-**	-	4
17	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	Foreign exchange gain (loss)	**(3)**	8	-
18	Net tax effect on comparable adjustments subject to tax	Unassigned	Income tax expense (recovery)	**2**	48	18
19	Deferred income tax rate adjustment	Unassigned	Income tax expense (recovery)	**1**	20	-
20	Reversal of writedown of deferred income tax assets	Unassigned	Income tax expense (recovery)	**(10)**	(56)	(5)
21	Income tax expense related to temporary difference on investment in subsidiary	Unassigned	Income tax expense (recovery)	**3**	95	-
22	Income tax recovery related to sale of investment	Unassigned	Income tax expense (recovery)	**-**	-	(36)
23	Non-comparable items attributable to non-controlling interest	Unassigned	Non-controlling interests	**4**	14	1

(1) Reported in net other operating (income) loss of ($191 million), depreciation and amortization of ($46 million), and fuel and purchased power of ($14 million).

Comparable Results

Discussion of Comparable FFO and Comparable FCF

The table below provides a reconciliation of our comparable EBITDA to our comparable FFO and comparable FCF.

Year ended Dec. 31	2016	2015	2014
Comparable EBITDA	1,145	945	1,036
Provisions	(85)	73	-
Unrealized losses from risk management activities	3	1	4
Interest expense	(219)	(230)	(236)
Current income tax expense	(23)	(19)	(33)
Realized foreign exchange gain	1	17	11
Decommissioning and restoration costs settled	(23)	(24)	(16)
Gain on curtailment and amendment of employee future benefit plans	-	(8)	-
Capital insurance recoveries	(1)	(7)	-
Other non-cash items	(35)	(8)	(4)
Comparable FFO	763	740	762
Deduct:			
Sustaining capital	(272)	(305)	(361)
Insurance recoveries of sustaining capital expenditures	1	25	4
Dividends paid on preferred shares	(42)	(46)	(41)
Distributions paid to subsidiaries' non-controlling interests	(151)	(99)	(84)
Comparable FCF	299	315	280

Comparable FFO was $763 million for 2016 as compared to $740 million for 2015. The full year contribution from renewable assets we acquired in late 2015 added $25 million to our comparable EBITDA and comparable FFO. Operations, maintenance, and administration ("OM&A") cost reduction initiatives across the fleet also increased comparable EBITDA and comparable FFO. Lower prices in Alberta and the Pacific Northwest negatively impacted our business, but the impact was mitigated by the high level of contracts and hedges in each market.

For the year ended Dec. 31, 2015, comparable FFO decreased by $22 million to $740 million compared to 2014, mainly due to the higher outages and derates in Alberta, and lower prices in Alberta and the Pacific Northwest.

Comparable FCF for 2016 was down by $16 million, largely related to higher distributions paid to subsidiaries' non-controlling interests. Higher comparable FCF in 2015 compared to 2014 was mostly due to lower sustaining capital expenditures as a result of reductions in mining expenditures, deferral of major work in Centralia as a result of economic dispatching, and reductions in our gas-fired capital expenditures caused by the Poplar Creek recontracting.

Discussion of Segmented Comparable Results

In 2016, we disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to net earnings attributable to common shareholders.

Each business segment assumes responsibility for its operating results measured to comparable EBITDA. Operating income and gross margin are also useful measures as they provide management and investors with a measurement of operating performance that is readily comparable from period to period.

Canadian Coal

Year ended Dec. 31	2016	2015	2014
Availability (%)	85.3	84.3	88.6
Contract production (GWh)	19,823	20,256	21,748
Merchant production (GWh)	3,787	3,827	3,806
Total production (GWh)	23,610	24,083	25,554
Gross installed capacity (MW)	3,791	3,786	3,771
Revenues	1,048	912	1,023
Fuel and purchased power	386	379	436
Comparable gross margin	662	533	587
Operations, maintenance, and administration	178	194	196
Taxes, other than income taxes	13	12	12
Gain on sale of assets	-	-	(1)
Net other operating income	(2)	(7)	(9)
Comparable EBITDA	473	334	389
Depreciation and amortization	307	299	292
Comparable operating income	166	35	97
Sustaining capital:			
Routine capital	33	48	56
Mine capital	23	25	45
Finance leases	13	10	10
Planned major maintenance	100	107	100
Total sustaining capital expenditures	169	190	211
Insurance recoveries of sustaining capital expenditures	-	(7)	-
Net amount	169	183	211

2016

Production for the year ended Dec. 31, 2016, decreased 473 gigawatt hours ("GWh") compared to 2015, primarily due to higher paid curtailments in the first half of the year and higher levels of economic dispatching, in both cases caused by lower prices in Alberta. This was partially offset by lower planned outages and derates. Unplanned outages remained at a similar level compared to last year.

Comparable EBITDA for the year ended Dec. 31, 2016, increased $139 million compared to 2015, primarily due to the reversal of the $80 million provision relating to the Keephills 1 outage in 2013. The year-over-year impact to comparable EBITDA of this provision was $139 million, as last year's comparable EBITDA was reduced by $59 million due to this provision. Our high level of contracted generation and hedging strategy largely mitigated the impact of low power prices in Alberta. Comparable EBITDA was also positively impacted by a reduction in our operations, maintenance, and administration costs.

For the year ended Dec. 31, 2016, sustaining capital expenditures decreased by $21 million compared to 2015, mainly due to lower expenditures on our turnaround outages executed on two of our operated units and deferral of discretionary projects into 2017.

2015

Production for the year ended Dec. 31, 2015, decreased 1,471 GWh compared to 2014, primarily due to unplanned outages in the first half of 2015 (Sundance 4 and the Keephills 1 outage) and derates due to high temperatures impacting cooling ponds in the spring and summer months. The planned outage at Sundance 3 was extended as a result of the level of turbine work required. Generation was also reduced due to economic dispatching resulting from the low price environment in 2015.

In 2015, comparable EBITDA included a $59 million adjustment to provisions primarily in relation to prior year events. Excluding the adjustment to provisions, comparable EBITDA would have been $393 million in 2015, in line with 2014. Reductions in operating expenses at our Highvale mine and mark-to-market gains on certain forward financial contracts that do not qualify for hedge accounting fully offset the negative impact of year-over-year lower availability on our comparable EBITDA. Our high level of contracts and hedges in Canadian Coal mostly offset the impact of lower prices in Alberta compared to 2014. Other operating income in 2015 represents insurance recoveries received in connection with the Keephills 1 force majeure outage and additional work at Sundance 3.

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

U.S. Coal

Year ended Dec. 31	2016	2015[2]	2014[2]
Availability (%)	88.1	87.4	82.8
Adjusted availability (%)[1]	88.9	89.5	87.7
Contract sales volume (GWh)	3,535	2,868	1,131
Merchant sales volume (GWh)	4,896	5,484	6,102
Purchased power (GWh)	(3,854)	(3,329)	(549)
Total production (GWh)	4,577	5,023	6,684
Gross installed capacity (MW)	1,340	1,340	1,340
Revenues	380	432	369
Fuel and purchased power	281	316	255
Comparable gross margin	99	116	114
Operations, maintenance, and administration	54	50	49
Taxes, other than income taxes	4	3	3
Comparable EBITDA	41	63	62
Depreciation and amortization	61	63	54
Comparable operating income (loss)	(20)	-	8
Sustaining capital:			
Routine capital	3	2	2
Finance leases	3	3	-
Planned major maintenance	11	10	10
Total	17	15	12

2016

Production was down 446 GWh in 2016 compared to 2015, due mainly to increased economic dispatching in the first half of the year caused by lower prices. We supplied our contractual obligations by buying less expensive power in the market during such periods.

Comparable EBITDA decreased by $22 million compared to 2015 as a result of reduced margins due to lower prices and the unfavourable impact of mark-to-market on certain forward financial contracts that do not qualify for hedge accounting. This was partially offset by lower coal transportation costs and a reduction in our coal impairment charges.

Depreciation and amortization for 2016 decreased by $2 million compared to 2015 due to higher discount rates being applied to our decommissioning obligation for the Centralia mine. As the mine is in the reclamation stage, the adjustment flows directly to earnings.

Sustaining capital expenditures for 2016 were $2 million higher compared to 2015, primarily due to higher planned outages.

(1) Adjusted for economic dispatching.
(2) Restated to include non-operating legacy U.S. Gas costs. Refer to the Accounting Changes section of this MD&A.

2015

Production decreased 1,661 GWh in 2015 compared to 2014, as a result of a higher level of economic dispatching caused by lower prices.

In December 2014, we began supplying power to Puget Sound Energy under a 10-year contract. Initial contracted capacity was 180 MW. Contract volumes escalated to 280 MW in December 2015 and to 380 MW in 2016. We can supply the contract by buying power from the market when economical to do so and further improve our margin. The contract is accounted for as a financial contract. Hedge accounting was applied to this contract, with changes in value recorded in other comprehensive income ("OCI").

EBITDA for the year ended Dec. 31, 2015, was comparable to 2014. The appreciation of the US dollar and lower pricing on uncontracted generation was offset by the increased contracted volumes with Puget Sound Energy.

Depreciation and amortization for 2015 increased by $9 million compared to 2014 due to the strengthening of the US dollar.

For the year ended Dec. 31, 2015, sustaining capital expenditures increased by $3 million compared to last year as a result of the coal fines recovery finance lease. This operation allows us to recover fuel as part of mine decommissioning activities.

Canadian Gas

Year ended Dec. 31	2016	2015	2014
Availability (%)	95.7	95.6	94.9
Contract production (GWh)	2,784	3,697	4,096
Merchant production (GWh)	288	1,535	2,027
Total production (GWh)	3,072	5,232	6,123
Gross installed capacity (MW)(1)	1,057	1,057	1,183
Revenues	470	486	584
Fuel and purchased power	171	204	299
Comparable gross margin	299	282	285
Operations, maintenance, and administration	54	67	69
Taxes, other than income taxes	1	3	4
Comparable EBITDA	244	212	212
Depreciation and amortization	108	98	98
Comparable operating income	136	114	114
Sustaining capital:			
Routine capital	7	4	22
Planned major maintenance	5	19	33
Total	12	23	55

(1) Includes production capacity for the Fort Saskatchewan power station, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor Energy ("Suncor"). We continue to own a portion of the facility and have included our portion as a part of gross capacity measures. Poplar Creek has been removed from our availability and production metrics, effective Sept. 1, 2015.

2016

Production for the year decreased 2,160 GWh compared to 2015, primarily due to the restructuring of our contract with Suncor at the Poplar Creek facility in the third quarter of 2015 and higher economic dispatching in Ontario driven by lower prices.

Comparable EBITDA for 2016 increased by $32 million compared to 2015, as result of a year-over-year change in unrealized mark-to-market on our gas position, cost-efficiency initiatives, and favourable pricing in Ontario from our contracts for power and gas. The recontracting of the Poplar Creek facility reduced our OM&A by more than $9 million in 2016, compared to last year.

Sustaining capital totalled $12 million in 2016, a decrease of $11 million. In 2015, we refurbished two engines in Ontario. The change in our Poplar Creek operation also lowered our sustaining capital by approximately $7 million compared to 2015.

2015

Production for the year ended Dec. 31, 2015, decreased 891 GWh compared to 2014, also as a result of the restructuring of our contract with Suncor at Poplar Creek, effective Sept. 1, 2015.

The Poplar Creek transaction had a minimal impact on EBITDA in 2015 compared to 2014.

Sustaining capital decreased by $32 million for the year ended Dec. 31, 2015 compared to 2014, due to the transfer of the Poplar Creek facility at the end of August, and lower planned maintenance activities resulting from condition-based assessments.

Australian Gas

Year ended Dec. 31	2016	2015	2014
Availability (%)	93.1	92.4	91.4
Contract production (GWh)	1,529	1,381	1,267
Gross installed capacity (MW)(1)	425	348	348
Revenues	174	163	159
Fuel and purchased power	20	20	23
Comparable gross margin	154	143	136
Operations, maintenance, and administration	25	21	33
Taxes, other than income taxes	1	-	-
Comparable EBITDA	128	122	103
Depreciation and amortization	20	20	16
Comparable operating income	108	102	87
Sustaining capital:			
Routine capital	3	4	2
Planned major maintenance	11	4	6
Total	14	8	8

(1) *Includes production capacity for the Solomon power station, which has been accounted for as a finance lease.*

2016

Production for 2016 increased 148 GWh compared to 2015 mostly from an increase in customer load. Due to the nature of our contracts, the increase did not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA for the year increased by $6 million compared to 2015, mainly due to the addition of capacity payments for the gas conversion project at our Solomon gas plant that was completed in May 2016, as well as the uplift from our natural gas pipeline that was commissioned in March 2015. The change in value of the Australian dollar had limited impact on our comparable EBITDA in 2016.

Sustaining capital increased by $6 million compared to 2015, mainly driven by maintenance projects on two engines in 2016 compared to maintenance projects on only one engine in 2015.

2015

Production for the year ended Dec. 31, 2015, increased 114 GWh compared to 2014 due to an increase in the power import regime at one of our customer's locations. Due to the nature of our contracts, the change did not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

The increase in comparable EBITDA was primarily attributable to revenue from the Australian natural gas pipeline, which was commissioned in March 2015. Revenue from our Solomon facility was also positively impacted by the appreciation of the US dollar. The Australian dollar remained at similar levels in relation to the Canadian dollar during 2015.

Most of our contracts provide for the pass-through of fuel costs to the counterparty, limiting our exposure to fluctuations in fuel prices. In the case where we have no provision for pass-through, we generally match our obligation to deliver energy and our fuel supply to minimize our exposure to volatile commodity prices. Revenue and costs of fuel decreased by similar amounts during the first half of 2015 compared to 2014, following the decrease in gas input costs. Also, certain operating costs that are transferred to customers are now billed directly to the customer, resulting in revenue and OM&A decreasing in 2015 compared to 2014.

Depreciation and amortization for 2015 increased by $4 million compared to 2014 due to the increased asset base associated with the Fortescue River Gas Pipeline completed in the first quarter of 2015.

Sustaining capital remained at similar levels in 2015 compared to 2014.

Wind and Solar

Year ended Dec. 31	2016	2015	2014
Availability (%)	94.9	95.8	94.6
Contract production (GWh)	2,301	2,146	2,228
Merchant production (GWh)	1,212	1,060	947
Total production (GWh)	3,513	3,206	3,175
Gross installed capacity (MW)[1]	1,408	1,424	1,291
Revenues	272	250	247
Fuel and purchased power	18	19	14
Comparable gross margin	254	231	233
Operations, maintenance, and administration	52	48	48
Taxes, other than income taxes	8	7	6
Net other operating income	(1)	-	-
Comparable EBITDA	195	176	179
Depreciation and amortization	119	99	88
Comparable operating income	76	77	91
Sustaining capital:			
Routine capital	2	1	2
Planned major maintenance	11	12	10
Total sustaining capital expenditures	13	13	12
Insurance recoveries of sustaining capital expenditures	(1)	-	-
Net amount	12	13	12

2016

Production for 2016 increased by 307 GWh compared to 2015, mainly due to the full year contribution from assets acquired during the second half of 2015, partly offset by lower wind resources negatively impacting generation across Canada.

Comparable EBITDA for 2016 increased $19 million compared to 2015, as assets acquired in the second half of 2015 contributed approximately $23 million to the increase. Lower merchant prices in Alberta and lower generation in Canada negatively impacted our EBITDA.

Depreciation and amortization increased by $20 million compared to 2015, primarily due to the addition of assets acquired during the second half of 2015.

2015

Production for 2015 increased slightly by 31 GWh compared to 2014, due to contributions from three additional wind farms and our first solar facility acquired during the second half of 2015 (111 GWh). This was partially offset by lower wind resources at Wyoming in 2015 compared to relatively high wind volumes in 2014.

Comparable EBITDA for 2015 was lower by $3 million compared to 2014 as lower generation from our Wyoming wind facility and lower merchant prices in Alberta were not fully offset by additional EBITDA from the acquired assets and the stronger US dollar.

Depreciation and amortization for 2015 increased by $11 million compared to 2014, primarily due to the acquisition of new assets during the year and a stronger US dollar.

(1) *Our 2015 capacity excludes acquisitions completed during the second half of 2015.*

Hydro

Year ended Dec. 31	2016	2015	2014
Contract production (GWh)	1,768	1,662	1,810
Merchant production (GWh)	88	86	75
Total production (GWh)	1,856	1,748	1,885
Gross installed capacity (MW)	926	926	913
Revenues	126	116	131
Fuel and purchased power	8	8	9
Comparable gross margin	118	108	122
Operations, maintenance, and administration	33	38	38
Taxes, other than income taxes	3	3	3
Net other operating income	-	(6)	(6)
Comparable EBITDA	82	73	87
Depreciation and amortization	33	25	24
Comparable operating income	49	48	63
Sustaining capital:			
Routine capital, excluding hydro life extension	8	3	9
Hydro life extension	9	18	19
Planned major maintenance	10	10	3
Total before flood-recovery capital	27	31	31
Flood-recovery capital	2	4	9
Total sustaining capital expenditures	29	35	40
Insurance recoveries of sustaining capital expenditures	-	(18)	(4)
Net amount	29	17	36

2016
Production for 2016 increased by 108 GWh over 2015, primarily due to better water resources.

Comparable EBITDA for 2016 increased $9 million compared to 2015. Higher generation contributed to higher revenues. Our financial contracts partially offset lower levels of revenues in the Alberta ancillary market, and we also benefited from cost-reduction initiatives implemented in late 2015.

Depreciation and amortization for 2016 increased by $8 million compared to 2015 due to the recognition of decommissioning obligations on certain transmission lines that were taken out of service. As these transmission lines are in the reclamation stage, the adjustment flows directly to earnings.

Sustaining capital (before insurance recoveries) for 2016 decreased $6 million compared to 2015 due to lower expenditures on hydro life extension projects, partially offset by higher expenditures on routine capital.

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

Comparable EBITDA decreased by $14 million for 2015 compared to 2014, primarily as a result of lower prices and a decrease in price volatility in Alberta, which limited our ability to take advantage of our flexibility to produce electricity in higher-priced hours. Net other operating income includes business interruption insurance recoveries relating to the 2013 Alberta flood.

Sustaining capital expenditures (before insurance recoveries) decreased by $5 million for the year ended Dec. 31, 2015 compared to 2014 mainly due to flood-recovery capital related to the Alberta flood of 2013.

Energy Marketing

Year ended Dec. 31	2016	2015	2014
Revenues and comparable gross margin	76	49	108
Operations, maintenance, and administration	24	12	33
Comparable EBITDA	52	37	75
Depreciation and amortization	3	1	-
Comparable operating income	49	36	75

Comparable EBITDA from Energy Marketing increased $15 million compared to 2015, as a result of solid performances in all markets where we are active. During the second quarter of 2015, unexpectedly volatile markets in Alberta and the Pacific Northwest negatively impacted gross margin. Operating, maintenance, and administration costs increased $12 million to $24 million in 2016 compared to 2015, due to increases in share-based incentive compensation and lower charges to other business segments for energy hedging and optimization services.

Corporate

Our Corporate overhead costs of $70 million were lower in 2016 compared to 2015 and 2014 ($72 million and $71 million, respectively), as we realized benefits of cost-efficiency initiatives that were offset by reduced allocations to our business segments.

Key Financial Ratios

The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. We are focused on strengthening our financial position and flexibility and aim to meet all our target ranges by 2018.

Comparable Funds from Operations before Interest to Adjusted Interest Coverage

As at Dec. 31	2016	2015	2014
Comparable FFO	763	740	762
Add: Interest on debt net of capitalized interest	223	223	236
Comparable FFO before interest	986	963	998
Interest on debt	239	232	239
Add: 50 per cent of dividends paid on preferred shares	21	23	21
Adjusted interest	260	255	260
Comparable FFO before interest to adjusted interest coverage (times)	3.8	3.8	3.8

Our target for comparable FFO before interest to adjusted interest coverage is four to five times. This ratio is comparable to last year, as 2016's higher comparable FFO was offset by higher interest on debt, which includes interest capitalized on our South Hedland power project. We expect this metric to improve towards our targeted level in the future, due the South Hedland power project, once commissioned.

Adjusted Comparable Funds from Operations to Adjusted Net Debt

As at Dec. 31	2016	2015	2014
Comparable FFO	763	740	762
Less: 50 per cent of dividends paid on preferred shares	(21)	(23)	(21)
Adjusted comparable FFO	742	717	740
Period-end long-term debt[1]	4,361	4,495	4,056
Less: Cash and cash equivalents	(305)	(54)	(43)
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt[2]	(163)	(190)	(96)
Adjusted net debt	4,364	4,722	4,388
Adjusted comparable FFO to adjusted net debt (%)	17.0	15.2	16.9

Our adjusted comparable FFO to adjusted net debt ratio improved to 17.0 per cent, mostly due to the increase in comparable FFO, and lower net debt due to repayments, and the strengthening of the Canadian dollar in 2016. We expect this metric to improve towards our targeted level of 20 to 25 in the future, due the South Hedland power project, once commissioned.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	2016	2015	2014
Period-end long-term debt[1]	4,361	4,495	4,056
Less: Cash and cash equivalents	(305)	(54)	(43)
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt[2]	(163)	(190)	(96)
Adjusted net debt	4,364	4,722	4,388
Comparable EBITDA	1,145	945	1,036
Adjusted net debt to comparable EBITDA (times)	3.8	5.0	4.2

During the year, our adjusted net debt to comparable EBITDA ratio improved compared to 2015, mainly because of a lower debt balance due to repayments and the strengthening of the Canadian dollar, and higher comparable EBITDA. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. We expect this metric to improve towards our targeted level in the future due to the expected increase in comparable EBITDA of approximately $80 million annually from the South Hedland power project, once commissioned.

Sustainability Performance

Stakeholder Communication and Value Creation

The information contained herein seeks to highlight our ability to create value for investors, stakeholders, and society in the short, medium, and long term. The selection of key information and key metrics disclosed in this integrated report and our full sustainability disclosures follow a materiality assessment process, which identifies key impact areas to our stakeholders. We subsequently are guided by, and place focus on, reporting on these key areas. More information on key areas of materiality can be found on the sustainability section of our website.

(1) Includes finance lease obligations and tax equity financing.

(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2016, Dec. 31, 2015, and Dec. 31, 2014.

Sustainability Targets and Results

Sustainability targets are strategic goals that support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas.

2016 Sustainability Targets

	Financial	Results	Comments
1. Maintain our investment grade rating	Achieve and maintain investment grade credit metrics	Partly achieved	TransAlta maintains investment grade ratings from three rating agencies: S&P (BBB-) stable, DBRS (BBB) negative outlook, and Fitch (BBB-) negative outlook. On Dec. 17, 2015, Moody's reduced our rating to Ba1
2. Increase focus on FFO and EBITDA	TransAlta targeted comparable EBITDA and comparable FFO for 2016 in the range of $990 million to $1,100 million and $755 million to $835 million respectively	Achieved	For the year ended Dec. 31, 2016, comparable EBITDA was $1,145 million and comparable FFO was reported at $763 million. Comparable EBITDA includes the reversal of provisions relating to the Keephills 1 force majeure event in the amount of $80 million

	Power Generating Portfolio	Results	Comments
3. Grow asset portfolio	Deliver an average of $40 million to $60 million of additional EBITDA from growth projects	On track	In 2016, we continued to exercise prudence and discipline in growing our cash flow. The wind and solar pojects acquired in late 2015 contributed approximately $25 million of comparable EBITDA in 2016. We continue to advance the construction of the South Hedland power project, on budget and on time. This project is expected to be commisioned by mid-2017 and add approximately $80 million of incremental annualized EBITDA
4. Achieve top-quartile performance in Canadian Coal	Continue to deliver 87 to 89 per cent availability in the segment	Not achieved	We achieved availability in 2016 of 85.3 per cent, compared to 84.3 per cent in 2015, lower than our targeted availability of at least 87 per cent. Our high level of contracted generation and hedging strategy mitgated lower power prices in Alberta. We continue to drive towards our targets

	Human and Intellectual	Results	Comments
5. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.70	Not achieved	IFR was 0.85 in 2016, up from 0.75 in 2015. We will continue to seek improvement in this area through deployment of additional targeted initiatives in 2017
6. Human Resources	a) Maintain voluntary turnover percentage under eight per cent	Achieved	Voluntary turnover was 6.7 per cent in 2016
	b) Achieve 100 per cent completion of development plans for all high-potential employees at the top three levels of the organization	Achieved	
	c) Complete the final three stages of our globally recognized leadership development project to ensure TransAlta's top three levels of leaders have the tools to successfully reposition and grow our business	Partly achieved	Final stages to be completed in Q1 2017

	Natural	Results	Comments
7. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 13	Not achieved	We recorded 16 reportable environmental incidents in 2016, none of which had a material environmental impact
8. Increase mine reclaimed acreage	Replace annual topsoil rate at Highvale mine at a rate of 74 acres/year	Partly achieved	Replaced topsoil on 38 acres in 2016. A warmer winter and early spring limited our ability to transport topsoil for placement without adversely impacting the ground surface (the preference is to drive on frozen soil)
9. Utilize coal byproduct	Sell a minimum of two million tonnes of coal byproduct materials during the period 2015 to 2017	On track	70 per cent achieved (long-term target)
10. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NO_x and SO_2 emissions by 2030	On track	We reduced levels of NO_x and SO_2 in 2016 and remain on track to realize these emission reductions by 2030
11. Reduce greenhouse gas emissions	a) 20 per cent reduction from 2005 levels of TransAlta coal facility GHG by 2021, or the equivalent of 7 million tonnes, of CO_2e per year	On track	We reduced GHG emissions in 2016, primarily as a result of lower coal production, and we remain on track to realize emission reductions by 2021/2030
	b) 55 per cent reduction from 2005 levels by 2030, or the equivalent of 19.7 million tonnes, of CO_2e per year.	On track	

	Social and Relationship Capital	Results	Comments
12. Combine stakeholder engagement	Implement final Stakeholder Engagement Framework. In 2016, every business unit will use a single framework for stakeholder guidance	Achieved	A corporate-wide framework was implemented and we introduced our Stakeholder and Aboriginal Relations ("STAR") tracking program. STAR is a communication record-keeping tool and fulfils our requirements for consultation with both stakeholders and aboriginal groups
13. Support youth education with community investment	50 per cent of total communitiy investment spending will be directed to supporting youth education	Partly achieved	In 2016 we spent approximately $0.75 million out of $2.5 million (30 per cent) on youth education. Funds were directed to the University of Calgary, University of Alberta, Southern Alberta Institute of Technology, Mount Royal University, The Banff Centre (indigenous leadership scholarships), Mother Earth's Children's Charter School (indigenous kindergarten to grade 9), Calgary Stampede (the Young Canadians - ages 7 to 18) and national Canada and U.S. indigenous scholarships (post-secondary for trades and academic)
14. Increase internal best practice aboriginal engagement awareness	Work with our aboriginal communities to develop an online best practice guide for employees on working with and engaging with aboriginal communities	Achieved	With the help of the First Nations groups and voices of those communities, we produced an Indigenous Awareness Training handbook for all our employees. This achievement is in line with a commitment to support the United Nations Sustainable Development Goals, specifically, goal 10: reduced inequalities

Competitive Forces

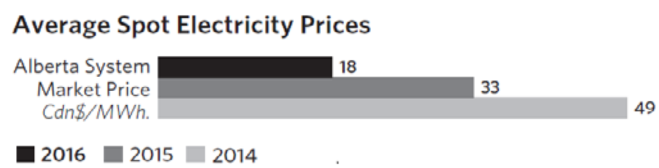
Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity, whereas system capacity, natural gas prices, GHG pricing, government subsidies, and renewable resource availability are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

Renewable capacity addition has been strong for the past several years due to government incentives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable energy as well as natural-gas-fired generation. This expectation is driven by the low prices in the natural gas market combined with public policies that favour carbon emission reductions.

We have substantial merchant capacity in Alberta and the Pacific Northwest. In those regions, we enter into contracts and business relationships with commercial and industrial customers to sell power on a long-term basis, up to our available capacity in the markets. We further reduce the portion of production not sold in advance through short-term physical and financial contracts, and we optimize production in real time against our position and market conditions.

We also compete for long-term contracted opportunities in renewable and gas power generation, including cogeneration, across Canada, the United States, and Australia. Our target customers in this area are incumbent utility providers and large industrial and mining operators.

Alberta



Approximately 63 per cent of our gross capacity is located in Alberta and more than 65 per cent of this is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. Alberta PPAs expire at the end of 2017 (Sundance 1 and 2) and the end of 2020 (Keephills 1 and 2, Sundance 3 to 6, Sheerness, and Hydro). Coal generation sold under Alberta PPAs retains some exposure to market prices as we pay penalties or receive payments for production below or above, respectively, targeted availability based upon a rolling 30-day average of spot prices. We can also retain proceeds from the sale of energy and ancillary services in excess of obligations on our Hydro Alberta PPAs ("hydro peaking"). We enter into financial contracts to reduce our exposure to variable power prices for a significant portion of our remaining generation.

Following the decrease in oil prices, Alberta's annual demand for power decreased by approximately 1.1 per cent in 2016 compared to 2015. Since 2014, approximately 1,000 MW of gas and wind generation capacity were added to the market. As a result, power pool prices trended to their lowest levels in the last 10 years, dropping to an average of $18/MWh in 2016, due to an oversupply of energy as well as bidding behaviour in the market that kept prices low. The decline impacted merchant wind and hydro peaking, which are the portions of our portfolio we cannot effectively hedge.

Our current share of offer control in the province is approximately 12 per cent. After the expiry of the PPAs at the end of 2020, our share of offer control is forecast to increase to approximately 28 per cent depending on load and supply growth in the province.

In late November 2016, we announced that we had entered into an OCA with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. We also entered into the MOU with the Government of Alberta to collaborate and co-operate in the development of a capacity market in Alberta that ensures both current and new electricity generators will have a level economic playing field to build, buy, and sell electricity, and to develop a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation. We expect additional compliance costs as a result of the federal government's proposed framework in which each province is expected to implement a greenhouse gas ("GHG") policy equivalent to a carbon price of $50 per tonne by 2022. We believe that our extensive portfolio of assets provides us with brownfield development opportunities in wind, solar, hydro, and gas that give us a cost advantage over competitors when constructing generation facilities that use these fuel types.

In March and May 2016, the buyers under the legislated Sundance, Sheerness, and Keephills PPAs announced their intention to terminate the PPAs and transfer their respective obligations under the PPAs to the Balancing Pool because of a change in Alberta law. Accordingly, the Balancing Pool began its investigation to determine whether these transfers are permitted by the terms of the PPAs in the current circumstances and, if so, when the transfers would become effective. On July 25, 2016, the Attorney General for the Province of Alberta commenced legal proceedings seeking relief against: all buyers who purported to transfer their respective obligations under the PPAs, the owner of the Battle River #5 PPA, the Alberta Utilities Commission ("AUC"), and the Balancing Pool. In this claim, the Attorney General challenges, among other things, the basis on which the buyers purported to terminate the PPAs and transfer their PPA obligations to the Balancing Pool.

Recently, the Attorney General announced that it entered into settlement agreements with the buyers of the PPAs for Sheerness, Sundance A, Sundance B, and Sundance C, and therefore discontinued its claims against those buyers. As part of the settlement, the Balancing Pool confirmed the terminations of the PPAs for Sheerness and Sundance A, B, and C and, as a result, the Balancing Pool assumed the role of buyer and is carrying out the responsibilities of the buyer under each of those PPAs, including dispatching the generating units and making the capacity and energy payments to TransAlta until the end of the PPA terms. TransAlta does not presently expect the transfer of the role of PPA buyer to the Balancing Pool to have a material impact on its business.

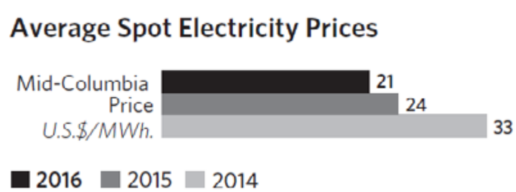
Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool may also choose to terminate the PPAs after following the legislative requirements, which would include paying TransAlta an amount essentially equal to the applicable closing net book value of the generating units.

The Attorney General has not entered into a settlement agreement with the buyer under the Keephills PPA and the Balancing Pool has not confirmed the termination of that PPA. The outcome of the Attorney General's proceeding and any investigation by the Balancing Pool into the purported termination of the Keephills PPA is uncertain.

Notwithstanding all the above events, TransAlta continues to operate the PPA generating units in their ordinary course and receives the capacity and energy payments due to TransAlta under the PPAs.

U.S. Pacific Northwest

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



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

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

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

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

While depressed commodity prices have reduced sectoral growth in the oil, gas, and mining industries, the change is also creating opportunities for us as a service provider as some of our potential customers are more carefully evaluating non-core activities and driving for operational efficiencies. In renewables, we are primarily evaluating greenfield opportunities in Western Canada or acquisitions in other markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities.

Some of our older gas plants are now reaching the end of their original contract life. The plants generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these plants with limited life-extending capital expenditures. We have recently extended the life of our Ottawa (2033 expiry), Windsor (2031 expiry), and Parkeston (2026 expiry) plants in this manner. During the fourth quarter of 2016, we entered into a new contract with the IESO for our Mississauga cogeneration facility. The new contract took effect on Jan. 1, 2017, and has resulted in the termination of the existing contract, which would have otherwise terminated in December 2018. See the Significant Events section for further details. The new contract provides us with additional financial flexibility to pay down upcoming debt maturities.

TransAlta's Capital

The following discusses TransAlta's main categories of capital, being Financial, Power Generating Portfolio, Human and Intellectual, Social and Relationship, and Natural.

Financial Capital

Sources of Capital
Our goal over the last two years was to build financial flexibility by using multiple sources of funding to reposition our capital structure. Over the last few years, the rating of our unsecured debt was put under pressure by all the rating agencies.[1] We responded to this pressure by taking significant action starting in 2014 and through to today to reduce our indebtedness and work on strengthening our financial metrics. Since the end of 2013, senior unsecured debt has been reduced by $1.1 billion, including a reduction of over $800 million on our credit facility and a $300 million reduction in Canadian and U.S. bonds. Over the next two years, we plan to continue on this path by replacing an additional $700 million to $900 million of maturing recourse debt with debt secured by contracted cash flows.

On Dec. 17, 2015, Moody's lowered the rating of our senior unsecured debt to Ba1 with a stable outlook. The direct financial impact of this downgrade has been limited. We have posted additional collateral (including letters of credit) of nearly $130 million to certain counterparties, and the cost of borrowing under our credit facilities and US$400 million of debt has been stepped up in line with contractual provisions. During the first quarter of 2016, DBRS and Fitch Ratings ("Fitch") changed their outlooks from stable to negative. Their negative outlooks are a reflection of low energy prices and concerns over coal generation transition in Alberta. We have investment grade ratings from each of DBRS, S&P, and Fitch. We remain focused on maintaining these ratings, as strengthening our financial position allows our commercial team to contract our portfolio with a variety of counterparties on terms and prices that are favourable to our financial results and provides us with better access to capital markets through commodity and credit cycles. Risks associated with further reductions in our credit ratings are discussed in the Liquidity Risk section of this MD&A.

(1) As at Dec. 31, 2016, our senior unsecured debt is rated as investment grade by three rating agencies: BBB (negative), BBB- (stable), and BBB- (negative) by DBRS, Standard and Poor's ("S&P"), and Fitch Ratings ("Fitch"), respectively, and Ba1 (stable) by Moody's Investors Service ("Moody's"). Our preferred shares are rated P-3 (stable) and Pfd-3 (negative) by S&P and DBRS, respectively. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The credit ratings accorded to our outstanding securities by DBRS, S&P, Moody's, and Fitch, as applicable, are not recommendations to purchase, hold, or sell such securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that the ratings will remain in effect for any given period or that a rating will not be revised or withdrawn entirely by DBRS, S&P, Moody's, or Fitch in the future if, in their judgment, circumstances so warrant. See the Liquidity Risk section of this MD&A.

Capital Structure

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

As at Dec. 31	2016 $	2016 %	2015 $	2015 %	2014 $	2014 %
Recourse debt - CAD debentures	**1,045**	**12**	1,044	12	1,043	13
Recourse debt - U.S. senior notes	**2,151**	**25**	2,221	26	2,444	31
Credit facilities	**-**	**-**	315	4	96	1
U.S. tax equity financing	**39**	**1**	50	1	-	-
Other	**15**	**-**	17	-	19	-
Less: cash and cash equivalents	**(305)**	**(4)**	(54)	(1)	(43)	-
Less: fair value asset of hedging instruments on debt	**(163)**	**(2)**	(190)	(2)	(96)	(1)
Net recourse debt	**2,782**	**32**	3,403	40	3,463	44
Non-recourse debt	**1,038**	**12**	766	9	380	5
Finance lease obligations	**73**	**1**	82	1	74	1
Total net debt	**3,893**	**45**	4,251	50	3,917	50
Non-controlling interests	**1,152**	**14**	1,029	12	594	8
Equity attributable to shareholders						
Common shares	**3,094**	**36**	3,075	35	2,999	38
Preferred shares	**942**	**11**	942	11	942	12
Contributed surplus, deficit, and accumulated other comprehensive income	**(525)**	**(6)**	(656)	(8)	(657)	(8)
Total capital	**8,556**	**100**	8,641	100	7,795	100

During 2016, we continued to work on strengthening our financial position and executing on our debt deleveraging strategy. Our total debt, net of cash on hand and the fair value of our financial instruments hedging our U.S. debt, was reduced by more than $350 million, from a combination of cash flows from operations and cash proceeds of $173 million received from the sale of the economic interest in the Canadian Assets. Furthermore, we extended $1.8 billion of our $2.0 billion credit facilities to 2020 and the remaining were extended to 2018. Since 2014, we acquired one wind and five solar projects for a total consideration of approximately $200 million, including the assumption of debt. These projects contributed approximately $25 million of comparable EBITDA in 2016. We also funded $336 million for the construction of the South Hedland project. In total, the South Hedland project is expected to cost approximately $576 million and add $80 million of EBITDA annually over the 25-year life of the long-term contract (including approximately $29 million of EBITDA relating to TransAlta Renewables' non-controlling interest share). We expect the project to commence operations in mid-2017.

During the year, we continued implementing our strategy to raise debt secured by our contracted cash flows and completed the following debt offerings:

- a non-recourse bond in the amount of $202.5 million, with principal and interest payable quarterly, maturing on Dec. 31, 2030, secured by our Poplar Creek finance lease contract, and
- a non-recourse bond in the amount of $159 million, with principal and interest payable semi-annually, and maturing on June 30, 2032, secured by our New Richmond Wind project in Quebec.

In 2015, we completed a $442 million bond offering, secured by two wind projects located in Ontario. The bonds are non-recourse to TransAlta, amortizing, and bear interest at a rate of 3.8 per cent, payable semi-annually, and mature on Dec. 31, 2028. On Feb 11, 2015, we also refinanced our $35 million 5.28 per cent Pingston non-recourse debt with a $45 million 2.95 per cent non-recourse bond due in full in 2023. We also added $105 million of non-recourse debt relating to the acquisitions of two renewable facilities in the U.S.

Non-recourse debt of $845 million in total (2015 - $536 million) is subject to customary financing restrictions that restrict our ability to access funds generated by certain facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. At Dec. 31, 2016, $24 million of cash was subject to these financial restrictions. Non-recourse debts of $644 million are each secured by a first ranking charge over all of the respective assets of our subsidiaries that issued the bonds, which includes renewable generation facilities with total carrying amounts of $956 million at Dec. 31, 2016 (2015 - $798 million). A non-recourse bond of approximately $201 million is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The weakening of the US dollar has decreased our long-term debt balances by $67 million in 2016. Almost all our U.S.-denominated debt is hedged either through financial contracts or net investments in our U.S. operations. During the period, these changes in our U.S.-denominated debt were offset as follows:

As at Dec. 31	2016	2015
Effects of foreign exchange on carrying amounts of U.S. operations (net investment hedge) and finance lease receivable	(35)	201
Foreign currency cash flow hedges on debt	(29)	183
Economic hedges and other	(3)	8
Total	(67)	392

Over the next four years, we have approximately $2.2 billion of recourse and non-recourse debt maturing. We expect to refinance some of these upcoming debt maturities by raising $700 million to $900 million of debt secured by our contracted cash flows. We also expect to continue our deleveraging strategy, as a significant part of our free cash flow over the next four years will be allocated to debt reduction. The reduction of our common share dividend in January 2016 is expected to provide additional funds which may be used for debt reduction.

Our credit facilities provide us with significant liquidity. At Dec. 31, 2016, we had a total of $2.0 billion (2015 - $2.2 billion) of committed credit facilities, of which $1.4 billion (2015 - $1.3 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2016, the $0.6 billion (2015 - $0.9 billion) of credit utilized under these facilities was comprised of actual drawings of nil (2015 - $0.3 billion) and letters of credit of $0.6 billion (2015 - $0.6 billion). These facilities are comprised of a $1.5 billion committed syndicated bank facility expiring in 2020, one bilateral credit facility of US$200 million, expiring in 2020, and three bilateral credit facilities, totalling $240 million, expiring in 2018.

Working Capital

Including the current portion of long-term debt, the excess of current assets over current liabilities was $337 million as at Dec. 31, 2016 (2015 - $311 million). Although our working capital has not changed significantly, the timing of the classification of long-term debt as current has negatively impacted our current period-end working capital. Excluding the current portion of long-term debt of $639 million, the excess of current assets over liabilities was $976 million as at Dec. 31, 2016 (2015 - $398 million). Working capital as at Dec. 31, 2016, also includes approximately $93 million of receivables related to the Mississauga recontracting and $61 million related to the Wintering Hills wind facility reclassified as assets held for sale. Last year, working capital included a $59 million provision relating to the Keephill 1 outage. We reversed a total of $94 million of this provision in the fourth quarter of 2016.

Share Capital

Our Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares reset in 2016 at a coupon rate of 2.709 per cent. As permitted under the terms of the Preferred Shares, some shareholders elected to convert to a floating rate and 1,824,620 of our 12 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares were tendered for conversion, on a one-for-one basis, into the Series B Cumulative Redeemable Floating Rate Preferred Shares.

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

As at	March 2, 2017	Dec. 31, 2016	Dec. 31, 2015
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	284.0
Preferred shares			
Series A	10.2	10.2	12.0
Series B	1.8	1.8	-
Series C	11.0	11.0	11.0
Series E	9.0	9.0	9.0
Series G	6.6	6.6	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

The Series C and Series E preferred shares will also reset in 2017. The rate spread on the Series C and Series E over the then 5-year Government of Canada bond rate is 3.10 per cent and 3.65 per cent, respectively.

Non-Controlling Interests

As of Dec. 31, 2016, we own 64.0 per cent (2015 – 66.6 per cent) of TransAlta Renewables. On January 2016, we completed the sale to TransAlta Renewables of an economic interest in the 506 MW Sarnia cogeneration facility and of two renewable energy facilities with total capacity of 105 MW for $540 million. Consideration received from TransAlta Renewables consisted of gross proceeds from a public offering of 17,692,750 common shares at $9.75 per share for gross proceeds of $173 million, 15.6 million common shares of TransAlta Renewables with a value of $152 million, and a $215 million unsecured subordinated debenture convertible into common shares of TransAlta Renewables at a price of $13.16 per common share upon maturity on Dec 31, 2020. In November 2016, the economic interest was converted to direct ownership of the Canadian Assets by TransAlta Renewables.

TransAlta Renewables is a publicly traded company whose common shares are listed on the Toronto Stock Exchange under the symbol "RNW". TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity. The stable and predictable cash flows generated by these assets has attracted favourable equity valuations from investors, allowing TransAlta to raise equity capital.

In November 2015, we sold 20.5 million common shares of TransAlta Renewables in a private placement to AIMCo for net cash consideration of $193 million.

On May 7, 2015, we completed the sale of an economic interest in our Australian assets to TransAlta Renewables. The Australian assets consist of six operating assets with an installed capacity of 425 MW, the 150 MW South Hedland project currently under construction, as well as a 270-kilometre gas pipeline, for total consideration of $1.78 billion. At the closing of the transaction, TransAlta Renewables paid the Corporation $217 million in cash as well as approximately $1,067 million through a combination of common shares and Class B shares in TransAlta Renewables. TransAlta Renewables has also committed to funding the costs to construct the South Hedland project incurred after Jan. 1, 2015, representing an estimated amount of $474 million. TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 common shares at a price of $12.65 per share.

We remain committed to maintaining our position as the majority shareholder and sponsor of TransAlta Renewables with a stated goal of maintaining our interest between 60 to 80 per cent.

We also own 50.01 per cent of TransAlta Cogeneration L.P ("TA Cogen"), which owns, operates, or has an interest in three natural-gas-fired facilities and one coal-fired generating facility. We recently recontracted our Mississauga cogeneration facility, which resulted in a pre-tax gain of approximately $191 million, accelerated depreciation of $46 million, and a fuel charge for the de-designation of gas hedges of $14 million. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets, and liabilities in relation to those assets.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2016	2015	2014
Interest on debt	236	228	238
Loss on redemption of bonds	1	-	-
Capitalized interest	(16)	(9)	(3)
Interest on finance lease obligations	3	4	1
Other	(5)	(2)	(1)
Keephills 1 outage interest accruals (reversals)	(10)	9	1
Accretion of provisions	20	21	18
Net interest expense	**229**	251	254

Net interest expense decreased in 2016 compared to 2015, primarily as a result of higher capitalized interest relating to the South Hedland power project and the reversal of the accrued interest component of the Keephills 1 provision. See the Other Consolidated Analysis section of this MD&A for further details. These decreases were partially offset by higher interest on debt, due partially to the downgrade to our credit rating from Moody's and higher average interest rates in 2016 as compared to 2015.

For the year ended Dec. 31, 2015, net interest expense decreased compared to 2014, primarily due to the reduction in debt during the year and lower interest rates on debt that was refinanced, coupled with higher capitalized interest. Higher interest expense on foreign-denominated debt due to the strengthening of the US dollar and other interest expense associated with the adjustment to provisions have partially offset these decreases.

Dividends to Shareholders

On Jan. 14, 2016, we announced a reduction of our common share dividend from $0.72 annually to $0.16 annually. This action was taken as part of a plan to improve our long-term financial flexibility. The declaration of dividends is at the discretion of the Board.

The following are the 2016 common and preferred shares dividends declared each quarter:

		Preferred Series dividends per share				
Year ended Dec. 31, 2016	Common dividends per share	A	B	C	E	G
First quarter	0.04	0.2875	-	0.2875	0.3125	0.33125
Second quarter	0.04	0.16931	0.15490	0.2875	0.3125	0.33125
Third quarter	0.04	0.16931	0.16144	0.2875	0.3125	0.33125
Fourth quarter	0.04	0.16931	0.15974	0.2875	0.3125	0.33125
Fourth quarter (1)	0.04	0.16931	0.15651	0.2875	0.3125	0.33125

During the year ended Dec. 31, 2016, 3.9 million (2015 – 9.0 million) common shares were issued to shareholders that elected to reinvest their dividends, for a total of $18 million (2015 - $76 million). On Jan. 14, 2016, we suspended the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP").

(1) On Dec. 19, 2016 the Board declared quarterly dividends per common share and preferred shares payable to shareholders of record at the close of business on March 1, 2017.

Non-Controlling Interests

Comparable earnings attributable to non-controlling interests for the year ended Dec. 31, 2016 increased, $23 million to $103 million compared to 2015, primarily due to the public offering of additional common shares by TransAlta Renewables to finance its investments in the Australian and Canadian portfolios in May 2015 and January 2016, respectively.

In 2015, comparable earnings attributable to non-controlling interests increased $31 million to $80 million compared to 2014, primarily due to the additional common shares issued to the public by TransAlta Renewables to fund its investment in the Australian portfolio.

Ability to Deliver Financial Results

The metrics we use to track our performance are comparable EBITDA, comparable FFO, and comparable FCF. The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		**2016**	2015	2014
Comparable EBITDA	Target	**990 - 1,100**	1,000 - 1,040	1,015 - 1,065
	Actual[1]	**1,145**	945	1,036
Comparable FFO	Target	**755 - 835**	720 - 770	743 - 793
	Actual	**763**	740	762
Comparable FCF	Target	**250 - 300**	265 - 270	274 - 324
	Actual	**299**	315	280

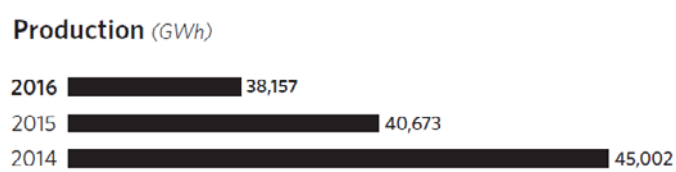
Power Generating Portfolio Capital

We monitor availability closely as a key metric to achieving our financial targets. We adjust our maintenance and sustaining capital expenditures to optimize financial returns on our investments and to align with our strategic orientations.

Availability and Production

Our adjusted availability target was 89 to 91 per cent for 2016.

Our availability in 2016, after adjusting for economic dispatching at U.S. Coal, was 89.2 per cent (2015 – 89.0 per cent, 2014 - 90.5 per cent) and was comparable to last year. Lower outages and derates at Canadian Coal were mostly offset by higher unplanned outages at our Eastern Wind facilities. Similar availability year-over-year did not impact our performance metrics.



Production for the year ended Dec. 31, 2016, decreased 2,516 GWh compared to 2015, primarily due to the Poplar Creek restructuring that occurred in late 2015 and lower generation from our coal portfolio due to lower prices in the Pacific Northwest and Alberta. Under our new arrangement with Suncor, they now operate the facilities and pay us a fixed monthly fee. Production from renewable assets acquired in the second half of 2015 contributed to partially offset generation lost from Poplar Creek. The Pacific Northwest continues to be dampened by lower prices, where it was more economic to supply our contractual obligation by buying power in the market, rather than through our own generation. In Alberta, lower prices impacted both paid and unpaid curtailments in 2016.

(1) *Over the last three years we have had a track record of delivering financial results well within or above guidance. Comparable EBITDA in 2015 and 2016 was impacted by non-cash adjustments related to the Keephills 1 provision. Excluding these adjustments, our Comparable EBITDA would have been $1,065 million in 2016 and $1,004 million in 2015.*

Operational

In the generation segments, our OM&A costs reflect the cost of operating our facilities. These costs can fluctuate due to the timing and nature of planned and unplanned maintenance activities. The remainder of OM&A costs reflect the cost of day-to-day operations.

OM&A costs were $22 million lower in 2016 compared to 2015 as we realized benefits from our cost control and targeted productivity initiatives. Over the last two years we reduced our OM&A costs by almost $40 million. The Poplar Creek restructuring also reduced OM&A costs throughout the year as the facility falls outside our operational scope.

The following table outlines our generation comparable OM&A over the last three years:

	2016	2015	2014
Generation comparable OM&A	396	418	433

We continuously drive for the cost-effective operation of our facilities. In 2015, we introduced multiple initiatives to reduce our overhead and increase efficiency and productivity at Canadian Coal. Aside from the reduction in the number of positions in Canadian Coal, we have driven reductions in coal costs through improved mine planning and mining methodologies, reduced equipment requirements, and optimized contractor usage.

Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital that ensures our facilities operate reliably and safely over a long period of time. Sustaining capital also includes capital required following the 2013 flood in Alberta, most of which has been recovered from third parties.

Year ended Dec. 31	2016	2015	2014
Routine capital	83	101	135
Mine capital	23	25	45
Planned major maintenance	148	162	162
Finance leases	16	13	10
	270	301	352
Flood-recovery capital	2	4	9
Total sustaining capital expenditures	272	305	361
Insurance recoveries of sustaining capital expenditures	(1)	(25)	(4)
Net amount	271	280	357

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

Year ended Dec. 31	2016	2015	2014
GWh lost[1]	938	1,409	1,519

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

Total sustaining capital expenditures were $33 million lower compared to 2015. At Canadian Coal, sustaining capital expenditures decreased by $21 million compared to 2015, mainly due to a reduction in maintenance projects without impacting our availability. At our Canadian Gas segment, sustaining capital expenditures decreased by $11 million compared to 2015, as we have been able to reschedule a large inspection of our gas generation units at Sarnia due to a lower number of operating hours. At our Australian Gas segment, planned major maintenance was up by $7 million in 2016 compared to 2015, driven by maintenance projects on two engines at our Kambalda and Kalgoorlie plants.

Strategic Growth

In 2016 we continued to explore opportunities to grow our cash flow but remained prudent and disciplined before allocating capital. We are focused on highly contracted gas and renewable power generation to support our financial position as we transition to having increased merchant capacity in Alberta post-2021. All investments are subject to due diligence procedures and are ultimately reviewed by our investment committee (refer to the Governance and Risk Management section of this MD&A).

Our South Hedland power project continues to progress in line with expectations. At the end of 2016 construction work was largely complete and the project team is now focusing on commissioning activities. The combined-cycle gas turbines achieved first fire in the fourth quarter and commissioning activities continue on these units. We expect to invest $230 million to $250 million to complete the construction of South Hedland, for a total cost of $576 million. We continue to expect the project to be delivered on schedule and on budget in mid-2017. The project is expected to add an additional $80 million of EBITDA annually, when fully in service.

In 2015 we completed two transactions and acquired:

- 71 MW of fully contracted renewable generation assets for cash consideration of US$76 million together with the assumption of certain tax equity obligations and US$42 million of non-recourse debt. The assets acquired include 21 MW of solar projects located in Massachusetts and the 50 MW Lakeswind wind project located in Minnesota. The assets are contracted under long-term power purchase agreements ranging from 20 to 30 years.
- As part of the restructuring of our Poplar Creek contract, we acquired the 20 MW Kent Breeze wind facility located in Ontario, which has a 20-year contract with the Ontario IESO and a 51 per cent interest in an 88 MW non-contracted wind facility in Alberta. Our interest in the Alberta wind facility was sold in early 2017.

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

Contractual Profile

Approximately 73 per cent of our capacity over the next two years is sold under long-term contracts. Excluding Alberta PPAs for our coal and hydro facilities, the majority of these contracts have maturities in excess of 10 years. In 2016, we entered into a long term contract for the Akolkolex hydro facility in B.C., expiring in 2045. Our South Hedland power project is expected to commence operations mid-2017, which will add stable contracted cash flows until the end of its 25-year contract life. Last year, significant contracts were extended at our Poplar Creek, Windsor, and Parkeston facilities, as discussed in more detail below. The average life of these contracts is approximately 12 years.

With most of our coal and hydro facilities in Alberta rolling off the Alberta PPAs at the end of 2020, we continue to develop a portfolio of commercial and industrial customers to sell our generation to the province. We are now serving a portfolio of approximately 450 MW.

Poplar Creek

In late 2015, we closed the restructuring of our contractual arrangement for power generation services with Suncor at Suncor's oil sands base site near Fort McMurray and the acquisition of Suncor's interest in two wind projects located in Alberta and Ontario.

The Poplar Creek cogeneration facility had been built and contracted to provide steam and electricity to Suncor until 2023. Under the terms of the new arrangement, Suncor acquired from TransAlta two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. In addition, Suncor assumed full operational control of the cogeneration facility, including responsibility for all capital costs and the right to use the full 244 MW capacity of TransAlta's gas generators until Dec. 31, 2030. We provide Suncor with technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030.

As part of the arrangement, we acquired Suncor's 20 MW Kent Breeze wind facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills merchant wind facility located in Alberta. The Kent Breeze facility has a 20-year contract with the Ontario IESO. On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million.

The Poplar Creek transaction creates value by increasing the duration of the contract to 2030 from the prior 2023 expiry, while the sale of Wintering Hills reduces our exposure to Alberta's merchant power market, and allows us an injection of near-term liquidity and financial flexibility to pay down debt. Additionally, we were able to further leverage our interest in the Poplar Creek cogeneration facility by completing a private placement in late December, of $202.5 million bonds that mature in 2030 and are secured by a first ranking charge over the equity interests of the issuer that issued such bonds, further allowing us to deleverage our corporate debt.

Windsor

During the first quarter of 2015, we executed a new 15-year power supply contract with the Ontario IESO for our Windsor facility, which was effective Dec. 1, 2016. The contract is similar to the contract signed in 2013 for our Ottawa facility. Under the new contract, the plant will become dispatchable for up to 72 MW of capacity. The new contract provides long-term stable earnings for this facility.

Parkeston

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

Over the last three years, we have nearly doubled the weighted average remaining contractual life of our gas fleet from six years to 12 years.

Human Capital

Engaging our workforce, developing our employees, and minimizing safety incidents are the keys to human capital value creation at TransAlta. The most material impacts an our human capital performance are an engaged workforce and keeping our employees safe.

As at Dec. 31, 2016, we had 2,341 active employees. This number has decreased by two per cent since the previous year, following various restructuring initiatives to reduce costs and increase efficiency. A number of unfilled positions have also been eliminated.

With approximately 53 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns, and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith, and we respect the rights of all employees to participate in collective bargaining.

Organizational Culture and Structure

Our employees are central to our value creation. Our corporate culture is one that has been cultivated throughout our more than 100-year heritage of pioneering innovative ways to safely and responsibly generate reliable and affordable electricity. In 2016 we formalized our core values to help provide strategic clarity for our employees. We want our people to align with and live our core values, which are: innovation, respect, loyalty, accountability, integrity, and safety. TransAlta has a stimulating work environment and we seek to challenge our employees to maximize their potential. We encourage alignment with our values and work ethic, while providing a foundation for leadership, collaboration, community support, growth, and work life balance.

During 2015 we initiated the Powering Performance organizational design program, with the primary objective of accelerating decision-making within our organization. The program has had us transition more fully to a decentralized, business-centric model, with Coal & Mining, Gas & Renewables, Australia, and Energy Marketing defined as our four primary businesses. As part of the design work, we have transferred accountability for shared services to the businesses and removed a layer of management. As part of this process, employees also have clearer accountabilities and authority.

Employee Benefits

TransAlta is an attractive employer in all three countries in which we operate. We provide compensation to our employees at levels that are competitive in relation to their respective location. We strive to be an employer of choice through our total rewards program, which includes various incentive plans designed to align performance with our annual and mid-term targets, as determined annually by the Board.

Also included in compensation are various future benefit plans. We have registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for members whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plans acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The defined benefit plans are funded by the Corporation in accordance with governing regulations. We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65. The supplemental pension plan is an obligation of the Corporation. We are not obligated to fund the supplemental pension plan but are obligated to pay benefits under the terms of the plan as they come due. We have posted a letter of credit in the amount of $73 million to secure the obligations under the supplemental pension plan.

Safety

At TransAlta we operate large and complex facilities. The environments in which we work – including Canadian winters and the Australian outback, often add an additional challenge to keep our employees safe. The safety of our staff, contractors, and visitors is one of the top priorities, if not the top priority, of our social performance. Our safety culture is further embedded into TransAlta culture each year. Every meeting of more than four people starts with a "safety moment," which helps share key safety learnings across our company. Our Operational Integrity program is focused on reducing safety hazards. Our core values include the safety of our people.

In 2016 our IFR was 0.85. IFR is defined as the number of lost-time and medical injuries for every 200,000 hours worked. Our ultimate goal is to achieve zero injury incidents, but annually we seek improvement over the prior year. We have experienced no fatalities during the last three years.

Year ended Dec. 31	**2016**	2015	2014
IFR	**0.85**	0.75	0.86

During 2015, we designed a new total safety management policy as a two-pronged approach. The policy builds on our occupational safety program, Target Zero, which is focused on protecting our workers on site, through means of personal protection equipment, inspections, safety controls, job safety analyses, field-level hazard assessments, and safety communications. The policy is supplemented by our newly launched Operational Integrity program, which is focused on preventing all hazards from equipment, through definition and measurement of safety-critical performance measures and operating limits.

Intellectual Capital

Intellectual capital at TransAlta is another key to our value creation. We have developed innovative solutions to optimize and maximize value from our fleet. We are constantly exploring use of applied or new technologies to find solutions to expand or adapt our fleet in an ever-changing world, which helps protect our shareholder value and maintain delivery of reliable and affordable electricity.

Operations Diagnostic Centre

TransAlta has maintained its Operations Diagnostic Centre ("ODC") since 2008. The ODC monitors coal-fired, gas-fired, and wind-generating assets across Canada, the United States, and Australia. A centralized team of engineers and operations specialists remotely monitors our power plants for emerging equipment reliability and performance issues. ODC staff are trained in the development and use of specialized equipment monitoring software and can apply their experience in power plant operations. If an equipment issue is detected, the ODC notifies plant operations to investigate and remedy the issue before there is an impact to operations. The monitoring, analysis, and diagnostics completed by the ODC are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day plant operations.

Operational Integrity Program

During 2015, we set the foundation for our Operational Integrity program. The program is designed to achieve process and equipment safety through understanding and monitoring of key risks and implementing of mitigation measures. In 2015, we completed our risk assessment at all facilities except Australia and Mining. We have also developed operator checks, maintenance tasks, and proof tests for various safety-critical elements at coal plants. Key performance indicators have been identified and are being integrated in a dashboard for ongoing monitoring. During 2016, we finalized developing the balance of safety-critical maintenance strategies and related engineering standards. We seek to optimize cost and reliability of our assets and maintain or increase their capacity. Our decentralized organization allows the sharing and deployment of technology-specific innovative practices within the respective businesses. Productivity projects are evaluated against criteria that include a two- to three- year financial payback. We also incurred $3 million in 2016 on a productivity improvement blade enhancement technology at our Wolfe Island wind project. This investment is expected to increase the annual energy production of the Wolfe Island wind project by approximately three per cent. In 2017 we are planning to put into place our Total Safety Management System where we integrate our work in Process Safety with our existing Occupational Safety programs. We continue to observe a positive increase in self-reporting and addressing process safety hazards as awareness and new tools are being introduced.

Energy Trading and Marketing

Our energy trading and marketing operations optimize the financial returns of our facilities in real time. The group purchases fuels to feed plants, bids the electricity we generate at our facilities into energy markets, and mitigates the associated risks associated with those purchases and sales. In addition, they buy, sell, schedule, and negotiate all of the electricity transmission for each facility. They do so while applying an overlay of complex, real-time information about weather, facility capacity, transmission congestion, and market pricing. Quantitative analysis, forecasting, mathematical models, and forward curves are key tools used to execute this responsibility. In addition, the application of these skills for proprietary trading allows us to generate positive margins.

Effective Jan. 1, 2016, a new Energy Trading and Risk Management System ("ETRMS") became operational, to further support optimization and trading capabilities, allowing for streamlined data flows, state-of-the-art linkages, and enhanced scalability for key optimization tools. The ETRMS was integrated into our internal control over financial reporting for the year ended Dec. 31, 2016.

Innovation: Applied Technologies
TransAlta has been at the forefront of innovation in the power generation sector since the early 1900s when we developed hydro assets. To add context, these assets were developed at the same time as the automobile. We have been an early adopter of wind technology in Canada and today are the largest wind generator in the country. Today we run a Wind Control Centre, the only one of its kind in Canada, that monitors, to the second, each and every wind turbine we operate across North America. In 2015 we made our first investment in solar technology with the purchase of the Massachusetts solar facilities.

As we move towards becoming the leading clean power company in Canada by 2030 we will continue to seek solutions to innovate. The announcement of our proposed Brazeau hydro expansion, a 600-900 MW pumped hydro expansion, which will double our hydro capacity in Alberta, demonstrates our ability to seek solutions to create value for both our shareholders and society. Hydro is a clean alternative to both coal and gas and has long-term life. We still operate some of our legacy hydro assets from the early 1900s today.

We strive to keep up to date with power technologies that have the potential to redefine power markets today and in the future. Innovation is constantly happening on a more micro scale at TransAlta. For further communication on innovation at TransAlta please visit www.transalta.com/about-us/innovation.

Social and Relationship Capital

Creating shared value for our stakeholders is the key to social and relationship value creation at TransAlta. The most material impacts to our social and relationship performance are public health and safety, anti-competitive behaviour and fostering better relationships and conditions with all stakeholders, but with a key focus on indigenous groups. Each year we strive to do better in each of these areas.

Public Health and Safety
We seek to ensure public health and safety through measures such as restricting physical access to our operating sites and by minimizing our environmental impact. It is our goal to both keep our employees safe and the peoples and the communities in which we operate.

We specifically look to protect against the following risks:
- harm to person(s),
- damage to property,
- increased liability due to negligence, and
- loss of organizational reputation and integrity.

When addressing concerns such as occupiers liability, our Corporate Security team liaises with stakeholders to facilitate appropriate security countermeasures and controls to prevent or reduce the identified risk. For example, in 2016 our Corporate Security term initiated a security/safety signage campaign across the Hydro fleet to elevate the awareness of the safety risks associated with dams. By implementing signage from a safety perspective, Corporate Security and TransAlta also benefited from a security perspective. Signage gave notice of potential physical dangers, but also allows as an organization and landowner to reduce liability and increase safety through notice, awareness, and mitigation of trespassing and vandalism.

We actively monitor air emissions from our coal and gas plants. Our large coal facilities have Continuous Emissions Monitoring Systems ("CEMS") in place, which help us monitor our pollutant emission levels in line with acceptable limits. When we are in breach of regulatory limits we report this to Alberta Environment & Parks and conduct a root cause analysis to understand how we can eliminate future breaches from occurring. In 2016 we had two breaches at our Alberta coal facilities. Both breaches were minor and due to an instrumentation calibration failure at Keephills 3 and an opacity CEMS analyzer failure at the Sundance operations.

Of note, our coal plants currently capture 80 per cent of mercury emissions and the majority of particulate matter emissions. Both have been deemed harmful to human health, which we recognize and work to minimize through capture. The health impact risk from emissions that do reach our environment is minimized due to the location of our plants, which are located away from urban environments. Independent studies conducted by University of Alberta scientist Dr. Warren Kindzierski, using provincial government monitoring data from the past nine years, also show that only approximately 10 per cent or less of all particulate matter in the airshed in the largest urban environment close to our facilities, Edmonton, can be attributed to coal combustion emissions. Chemical "signatures" for emissions pointed to several sources of air quality concern in Edmonton, including local industries, vehicles, and wood-burning fireplaces.

We are currently evaluating the option of converting some of our coal-fired units to natural gas units in 2022 and 2023, which will represent 90 per cent of our coal fleet at that point in time. This action will reduce our GHG emissions by close to 50 per cent. It will also eliminate the majority, if not all, of our mercury emissions and nitrogen oxide emissions from our Alberta coal facilities.

Stakeholder Relations

TransAlta implemented a corporate stakeholder engagement framework in 2016, a streamlined corporate-wide approach to ensure that engagement and relationship-building practices are consistent across TransAlta's locations and types of work. This framework is modelled and closely tied to the stakeholder engagement aspect of ISO 14001, which is an internationally recognized environmental management standard.

In 2016 we introduced our Stakeholder and Aboriginal Relations ("STAR") tracking program. STAR functions as a communication record-keeping tool, which is managed by our Stakeholder and Aboriginal Relations team. This capacity fulfils our requirements for consultation with stakeholders and aboriginal groups alike, and is capable of producing reports (notably, government reports) as proof of engagement and consultation efforts. Built as a SharePoint page, STAR has the capacity to centralize information and grant different levels of access to the information it stores.

Some features of the STAR program include:

- in-house application with no operating cost or fees,
- centralized for the entire company to use,
- different levels of accessibility (privileges),
- can store email conversations, documents, and voice-mail messages related to any project, event, or issue; and use them in reports, and
- produces an array of statistical reports showing frequencies and volumes of engagement based on project, stakeholder, stakeholder group, issue, or keywords.

The Board believes that it is important to have constructive engagement with its shareholders and other stakeholders and has established means for the shareholders of the Company and other stakeholders to communicate with the Board through the use of a confidential Ethics Helpline or by writing directly to the Board. The contact information for communicating with the Board is published in Whistleblower section of this MD&A. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. In addition, the Board has adopted an annual non-binding advisory vote on the Company's approach to executive compensation. The Company is committed to ensuring continued good relations and communications with its shareholders and other stakeholders and will continue to evaluate its practices in light of any new governance initiatives or developments.

Aboriginal Relations

The focus of our efforts in this area is to establish solid relationships with indigenous and Métis communities, recognizing and respecting their rights and focusing on engaging them at the earliest stages of any project or development. Specifically, our aboriginal relations team continues to develop and enhance aboriginal relations in areas of employment, economic development, community engagement, and investment. Since 2014, we have achieved the Canadian Council for Aboriginal Business's silver-level Progressive Aboriginal Relations certification. As noted above, in 2016 we introduced our STAR tracking program, which functions a communication record-keeping and engagement measurement tool.

Local Communities

We provide public benefit through reliable, cost-efficient power and related outputs or services. With the phase-out of coal on the horizon, we seek to secure favourable outcomes for our workers and the communities surrounding our plants. Our proposed coal-to-gas conversions provide the opportunity to maintain some jobs during conversions, to support sector jobs, and to redeploy some of our workforce in the plants or toward renewables growth. Electricity and energy have always been at the heart of the economy in Alberta, and any changes in the industry must therefore support our communities. Conversion will also help keep municipal, provincial, and federal tax revenues supporting these communities. TransAlta advocates for sufficiently long timelines for transition, support for facility redevelopment, funds for retraining, and economic diversification.

Community

During 2016, TransAlta contributed $2.5 million in donations and sponsorships (2015 - $3.5 million).

On July 30, 2015, we announced that we were moving ahead with plans to invest US$55 million over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State. The US$55 million community investment is part of the TransAlta Energy Transition Bill, passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders, and TransAlta to transition away from coal in Washington State, closing the Centralia facility's two units, one in 2020 and the other in 2025. Although we did not secure additional long-term contracts totalling 500 MW as planned in the original agreement as a condition of the investment, we are following through on our funding pledge and securing mutual benefits agreed with the State for orderly transition.

Competitive Behaviour

On July 27, 2015, the AUC issued a ruling that found, among other things, that our actions in relation to four outage events at our coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated PPA buyers and manipulated market prices away from a competitive market outcome.

On Sept. 30, 2015, TransAlta and the Alberta Market Surveillance Administrator ("MSA") reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which was in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the agreement, we agreed to pay a total amount of $56 million that included approximately $27 million as a repayment of economic benefits, approximately $4 million to cover the MSA's legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million was paid in the fourth quarter of 2015, and $25 million was paid in the fourth quarter of 2016.

When we became aware that the market rules governing forced outages were in dispute, we changed our compliance procedures, and the actions that led to this case have not been repeated. In order to rebuild trust, we asked a national law firm with expertise in electricity markets, and a national accounting firm, to complete independent third-party reviews of our then current compliance procedures around forced outages. We also asked them to review our trading compliance program to ensure that our current practices met the company's legal and ethical obligations and the high expectations of our customers and stakeholders, the results of which were made public during the first half of 2016.

The national law firm assessment concluded that:

- outage practices are consistent with the law in Alberta, and
- senior management has demonstrated a strong commitment to compliance.

Recommendations were provided to formalize the outage practices and procedures and related document management, and to incorporate the procedures into the existing TransAlta Compliance programs in terms of training, investigation procedures and annual reviews.

Using a 10-point compliance effectiveness review framework, the national accounting firm's assessment of TransAlta's Energy Trading Compliance Program concluded that:

- from a program design perspective, TransAlta's program contains each of the 10 components of an effective compliance program, and includes the key elements required and normally seen at industry peers, and
- in terms of operational effectiveness, TransAlta's program meets or exceeds current industry practice in each of the 10 components.

Recommendations were provided in 5 of the 10 areas, for increasing cross functional communications, cross-training of compliance staff, scheduling of training components more frequently throughout a year, formalizing documentation of monitoring tools and performance review assessments for compliance.

TransAlta has accepted all of the recommendations in both reports.

Natural Capital

All energy sources used to generate electricity have some impact on the environment. While we are pursuing a business strategy that includes investing in low-impact renewable energy resources such as wind, hydro, and solar, we also believe that natural gas will continue to play an important role in meeting energy needs as part of this transition. Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost electricity. Currently the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (pollutants, metals), and energy use. Material impacts that we manage and track include our environmental management systems, environmental incidents and spills, land use, water usage, and waste management.

In the jurisdictions in which we operate, legislators have proposed and enacted regulations to discontinue, over time, the use of the technologies our coal-fuelled plants currently utilize. Our gas and coal facilities can also incur costs in relation to their carbon emissions, depending on the jurisdiction in which the facility is located. Our contracted facilities can generally recover those costs from the customer. Conversely, our renewable generation facilities are generally able to realize value from their environmental attributes. We continue to closely monitor the progress and risks associated with environmental legislation changes on our future operations.

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

Our environmental initiatives include:

- Renewable power growth and offsets portfolio: Over the last 10 years, we have added approximately 1,300 MW in renewable energy capacity. From our Alberta wind fleet, 360 MW of capacity generates offsets that can be applied against GHG emissions in Alberta. Annual revenue generation from these offsets is in the range of $10 million to $15 million.
- Environmental controls and efficiency: We continue to make operational improvements and investments to our existing generating facilities to reduce the environmental impact of generating electricity. We installed mercury control equipment at our Canadian Coal operations in 2010 in order to meet Alberta's 70 per cent reduction objectives, and voluntarily at our U.S. coal-fired plant in 2012. In 2016 we achieved an 80 per cent capture rate of mercury at all coal facilities. Our Keephills 3 and Genesee 3 plants use supercritical combustion technology to maximize thermal efficiency, as well as sulphur dioxide ("SO_2") capture and low oxides of nitrogen ("NOx") combustion technology. Uprate or energy- efficiency projects completed at our Keephills and Sundance plants, including a 15 MW uprate finalized in 2015 at Sundance 3, have improved the energy and emissions efficiency of those units.
- Planning: With respect to environmental rules (as detailed in the following Regional Regulation and Compliance subsection), we investigate the cost effectiveness of multiple technological solutions and various operating models in order to prepare appropriate work scopes. In 2016 we announced our proposed coal to natural gas conversions and support for the Government of Alberta's renewable electricity plans.
- Policy participation: We are active in policy discussions at a variety of levels of government and with industry participants. Where capacity retirements are being mandated, we advocate minimizing the capital requirements of incremental regulation, to allow reinvestment in lower-intensity sources during the transition phase. In Washington State, the retirement of our Centralia coal plant was established through a multi-stakeholder agreement. In 2016 we entered into the MOU with the Government of Alberta, which entails co-operation and collaboration to enable the conversion of coal-fired generation to gas-fired generation.

In addition to these initiatives, we maintain similar procedures for environmental incidents as we do for safety, with tracking, analyzing, and active management to eliminate occurrence, and ongoing support from our Operational Integrity Program. With respect to biodiversity management, we seek to establish robust environmental research and data collection to establish scientifically sound baselines of the natural environment around our facilities and closely monitor the air, land, and water in these areas to identify and curtail potential impacts.

Environmental Performance

All of our 69 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely mimic the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for 17 years, and our systems and knowledge of management systems are therefore mature. In 2016 we moved to no longer certify our Alberta coal plants as ISO 14001, but the plants continue to run best practice EMS, as do 97 per cent of our facilities. Only two of our facilities do not closely track ISO 14001, which is due to commercial arrangements (we are not the primary operator), but these facilities still have EMS in place.

Environmental Incidents and Spills

We recorded 16 reportable environmental incidents in 2016 (2015 - 12 incidents), which was above our target of 13. None of these incidents resulted in a material environmental impact. Our Gas & Renewables fleet recorded only three incidents in 2016, a record year. The remainder of our 13 environmental incidents occurred at our Alberta Coal business unit. Incident types included spills, which were highly recoverable, air emission exceedances or instrument failures, wastewater sampling errors, effluent releases, water blowdown exceedances, and process safety incidents. We will continue to target improvement in 2017 with a specific focus on Alberta Coal. Our corporate-wide 2017 target is 11 or fewer incidents. We also continue to track and manage all non-reportable (minor) environmental incidents, which helps us identify what leads to an incident. Understanding the root cause of incidents helps with incident prevention planning and education.

Typical spills at TransAlta are hydrocarbon spills, which happen in low environmental impact areas and are almost always contained and recovered. It is extremely rare that we experience large spills with impact on the environment. Spills that do occur that we must report are typically just above acceptable regulatory spill limits and these are always addressed with a critical time factor. The volume of spills in 2016 was 61 m^3 (2015 - 19 m^3), of which 78 per cent was recovered (2015 – 99 per cent recovered). The increase is attributable to three large spills, two at our Sundance coal operations and one at Mt Keith in southwestern Australia. All three incidents were contained at our sites and were reported to the appropriate bodies.

Energy Use

TransAlta uses energy in a number of different ways. We burn coal, gas, and diesel to generate electricity. We harness the kinetic energy of water and wind to generate electricity. We also utilize the sunshine to generate electricity. In addition to combustion of fuel sources we also track combustion of fuel in the vehicles we use and energy use in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies.

The following are our millions of gigajoules of energy use. On a comparable basis, our energy use has declined over the last three years as a result of lower generation from our coal-generating assets.

Year ended Dec. 31	2016	2015(1)	2014
Coal	469.1	483.4	529.7
Gas and Renewables	59.2	58.7	54.3
Corporate	0.1	0.1	0.1
Total energy use	528.4	542.2	584.1

(1) *Gas & Renewable 2015 volumes were restated due to a diesel volume reporting error at our Solomon facility.*

Greenhouse Gas Emissions

In 2016, we estimate that 30.7 million tonnes of GHGs with an intensity of 0.84 tonnes per MWh (2015 - 32.2 million tonnes of GHGs with an intensity of 0.87 tonnes per MWh) were emitted as a result of normal operating activities.[1] Our GHG emissions decreased slightly in 2016, primarily as a result of lower production from coal plants. Other decreases in emissions of the Canadian Gas segment are attributable to the transfer of operational control of the Poplar Creek facility to our customer in September 2015, conversion of the Ottawa plant to a peaking facility in 2013, and conversion of the Solomon plant in Australia to burn natural gas instead of diesel.

The following are our GHG emissions in million tonnes CO_2:

Year ended Dec. 31	2016	2015	2014
Coal	27.7	29.2	32.3
Gas and renewables	3.0	3.0	2.7
Total GHG emissions	30.7	32.2	35.0

Our continued investment in growth from renewable power generation further supports the decrease in emissions intensity observed in 2016. We believe in proactive measurement and disclosure of air emissions.

In 2016, TransAlta improved its scoring on the Carbon Disclosure Project Climate Change report to a B, our highest integrated score yet. We were also highlighted by Chartered Professional Accountants of Canada as the only company in Canada, out of 75 companies, that reports on climate change across all levels of disclosure: the annual information form, this MD&A, and our information circular.

Refer to the Climate Change section of this MD&A for further information.

Air Emissions

In 2016 air emissions were down compared with 2015. Air emissions decreased slightly in line with reduction in coal power generation.

Year ended Dec. 31	2016	2015	2014
Sulphur dioxide (tonnes)	39,600	41,800	47,600
Nitrogen oxide (tonnes)	48,400	48,000	52,900
Particulate matter (tonnes)	4,900	4,900	5,200
Mercury (kilograms)	130	170	220

Our continued investment in growth from renewable power generation further supports the decrease in emissions intensity observed in 2016. We believe in proactive measurement and disclosure of air emissions.

(1) *2016 data are estimates based on best available data at the time of report production. GHGs include water vapour, carbon dioxide ("CO_2"), methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion.*

Emissions intensity data has been aligned with the 'Setting Organizational Boundaries: Operational Control' methodology set out in The GHG Protocol: A Corporate Accounting and Reporting Standard. As per the methodology, TransAlta reports emissions on an operation control basis, hence we report 100 per cent of emissions at facilities in which we are the operator. Emissions intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, regardless of financial ownership.

Water

Our principal water uses are for cooling and steam generation in coal and gas plants, and for hydro power production. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2016 we withdrew 247 million m^3 and returned approximately 188 million m^3 back to its source. Water is withdrawn primarily from rivers where we hold permits to withdraw water and adhere to regulations on water quality. We return or discharge approximately 70 per cent of water back to the source, meeting the regulatory quality levels that exist in the various locations in which we operate. The difference between withdraw and discharge, representing consumption, is largely due to evaporation loss.

The following represents our total water consumption (million m^3) over the last three years:

Year ended Dec. 31	2016	2015	2014
Water from environment	247	272	243
Water to environment	188	198	172
Total water consumption	59	74	71

Our areas of higher water risk are situated east of Perth in our simple-cycle gas plants in Western Australia and in our Southern Alberta hydro operations. We monitor and manage water risk in our operating areas east of Perth.

In Southern Alberta, following the flood of 2013, our hydro facilities are being used for an increased water management role than they have played in the past. During 2016, we signed a five-year agreement with the Government of Alberta to manage water on the Bow River at our Ghost reservoir facility to aid in potential flood mitigation efforts, as well as at our Kananaskis Lakes System (which includes Interlakes, Pocaterra and Barrier), for drought mitigation efforts.

Land Use

The largest land use associated with our operations is for surface mining of coal. Of the three mines we have operated, Whitewood is completely reclaimed and the land certification process is ongoing. Centralia is in the reclamation phase, and Highvale is actively mined with ongoing reclamation. Our reclamation plans are set out on a lifecycle basis and include contouring disturbed areas, re-establishing of drainage, replacing topsoil and subsoil, re-vegetation, and land management. Our mining practice incorporates progressive reclamation where the final end use of the land is considered at all stages of planning and development.

In 2016, we reclaimed 39 acres (16 hectares) at our Highvale mine, which was below our target of 74 acres (30 hectares) due to the impact of warm weather on soils in the winter, as cold temperatures facilitate reclamation work and the spreading of topsoil. The Centralia mine is no longer actively used for coal operations, but reclamation activity is ongoing. In 2016 we reclaimed 38 hectares of land.

Also in 2015, we donated 64 acres of land to the Alberta Wildlife Trust Fund. The land includes an area that was once a mine settling pond and is a site of ecological significance. The donation aligns with our objectives for community participation and stakeholder engagement.

Waste

Our operating teams work to minimize waste and maximize recoverable value from waste. Over the years, we have invested in equipment to capture byproducts from the combustion of coal, such as fly ash, bottom ash, gypsum, and cenospheres, for subsequent sale. These non-hazardous materials add value to products like cement and asphalt, wallboard, paints, and plastics. Byproduct sales and associated annual revenue generation typically ranges from $25 million to $35 million.

Coal Transition

Our coal transition, whether it is executing on our coal-to-gas conversion plans or completing a full phase-out by 2030, will vastly improve our environmental performance. Energy use, GHG, air emissions, waste generation, and water usage will all significantly decline. A conversion of coal-fired power generation to gas-fired generation is expected to eliminate all mercury emissions and the majority of nitrogen oxide emissions.

Climate Change

Governance

TransAlta's Governance and Environment Committee ("GEC") is a Board-appointed committee that reports directly to the Board of Directors to help fulfil oversight responsibility with respect to environment, health, and safety. In conjunction, the GEC and Board hold the highest levels of oversight in regards to TransAlta's climate change policy and sustainability initiatives.

Strategy

Climate change related risks are monitored through our company-wide risk management processes and actively managed. Identified climate change risks and opportunities are also reviewed by our management team . We attribute regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks pertaining to uncertainty in the carbon market and as a safeguard to anticipate future impacts of regulatory changes on facilities. It is also a method of modelling for future electricity prices and to analyze the viability of acquisitions. Identified climate change risks or opportunities and carbon pricing are recognized in the annual TransAlta long-and-medium range forecasting processes. Regulatory risk/compliance (coal electricity generation), physical risks (hydro and drought/floods), and monetary opportunities (gas and renewable electricity generation) are the main drivers of integration into business strategy.

Aligned with our business strategy is our climate change strategy, which is implemented and managed on a corporate-wide business unit level, consisting of four main areas of focus:

- Energy-efficiency improvements,
- Development of emissions offsets portfolios to achieve emissions reductions at competitive costs,
- Development of clean combustion technologies,
- Growth of our renewables portfolio as an increasing component of our total generation portfolio.

We seek investment in climate change related mitigation solutions where we can maximize value creation for our shareholders, local communities, and the environment. Anticipated conversion of our large coal fleet to gas-fired generation highlights this approach, which will allow us to run our assets longer than the federally mandated coal retirement schedule. Our anticipated actions maximize value for our shareholders, ensure low-cost and reliable power for Albertans, and reduce the environmental impact from coal-fired generation.

Our investment and growth in renewable energy is highlighted by our diverse portfolio of renewable energy generating assets. We currently operate and are invested in over 2,200 MW of hydro, wind, and solar power. We are the largest producer of wind power in Canada and the largest producer of hydro in Alberta. Production from renewable energy in 2016 resulted in avoidance of over 3.1 million tonnes of CO2e, which is equivalent to removing over 730,000 vehicles from North American roads. For further details on governance and risk, see our Governance and Risk Management section of this MD&A.

Targets

We recognize climate change risk and the goal set out in the 2015 Paris Agreement to prevent two degrees Celsius of global warming above pre-industrial levels. Our GHG reduction targets have been established to align with the UN Sustainable Development Goals, specifically Goal 13, which calls for "urgent action to combat climate change and its impacts." Our 2030 GHG reduction target is set based on climate-based science and the goal of preventing two degrees Celsius of global warming. This target is approved by the Science Based Targets initiative, which is a partnership between the Carbon Disclosure Project, UN Global Compact, World Resources Institute and World Wildlife Fund, which helps companies determine how much they must cut emissions to prevent the worst impacts of climate change.

Our GHG reduction targets are as follows:

1. Our goal, in line with a commitment to the UN Sustainable Development Goals ("SDGs"), is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels.
2. Our goal, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming, is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels.

Regional Regulation and Compliance

Carbon issues and related legislation will continue to have an impact on our business. We are committed to complying with legislative and regulatory requirements and to minimizing the environmental impact of our operations. We work with governments and the public to develop appropriate frameworks to protect the environment and to promote sustainable development.

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

Canadian Federal Government

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

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

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

Alberta

On Nov. 22, 2015, the Government of Alberta announced through the Climate Leadership Plan its intent, among other things, to phase out emissions from coal-fired generation by 2030, replace two-thirds of the retiring coal-fired generation with renewable generation, and impose a new carbon price of $30 per tonne of CO_2 emissions based on an industry-wide performance standard. On March 16, 2016, the Government of Alberta announced the appointment of a Coal Phase-out Facilitator to work with coal-fired electricity generators, the Alberta Electric System Operator ("AESO"), and the Government of Alberta to develop options to phase out emissions from coal-fired generation by 2030. The Coal Phase-out Facilitator was tasked with presenting options to the Government of Alberta that would strive to maintain the reliability of Alberta's electricity grid, maintain stability of prices for consumers, and avoid unnecessarily stranding capital.

In March 2016, Alberta began development of its renewable energy procurement process design for the AESO to procure a first block of renewable generation projects to be in-service by mid-2019. On Sept. 14, 2016, the Government of Alberta reconfirmed its commitment to achieve 30 per cent renewables in Alberta's electricity energy mix by 2030.

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

On Nov. 24, 2016, we announced that we had entered into the OCA, which provides for transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. Under the terms of the OCA, the Corporation will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. For further details, refer to the Highlights section of this MD&A.

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

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

- On Jan. 1, 2016, an increase in the GHG reduction obligation for large emitters from 12 per cent to 15 per cent of emissions, with the compliance price of the technology fund rising from $15 per tonne to $20 per tonne.
- On Jan. 1, 2017, a further increase to a 20 per cent reduction requirement and a $30 per tonne compliance price.

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

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

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

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

Pacific Northwest

On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the state, which is where our U.S. Coal plant is located. Included in this program are a cap-and-trade plan and a low-carbon fuels standard. The proposed emissions cap will become more stringent over time, providing emitters time to transition their operations.

On Aug. 3, 2015, former U.S. President Obama announced the Clean Power Plan. The plan sets GHG emission standards for new fossil-fuel-based power plants and emission limits for individual states. States will have the option of interpreting their limits in mass-based (tons) or rate-based (pounds per MWh) terms. The plan is intended to achieve an overall reduction in GHG emissions of 32 per cent from 2005 levels by 2030. It will be implemented in two stages: 2022 to 2029, and 2030 and beyond.

On Feb. 9, 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending consideration as to whether the regulations are lawful. It is not clear yet how this may affect the future of the Clean Power Plan. As a result of our 2011 agreement for coal transition with the State of Washington, we do not expect the proposed regulations to significantly affect our U.S. operations.

These additional regulations for existing power plants are not expected to significantly affect our U.S. operations. TransAlta has agreed with Washington State to retire units in 2020 and 2025. This agreement is formally part of the State's climate change program. We currently believe that there will be no additional GHG regulatory burden on U.S. Coal given these commitments. The related TransAlta Energy Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation.

Ontario

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

Australia

In Australia, the Senate recently passed amendments to the country's Renewable Energy Target Scheme. The scheme was initially introduced in 2001 with three objectives: to establish a mandatory renewable energy target to be achieved in 2020; to provide incentives for large-scale renewable energy generators in the form of one large-scale generation certificate earned for each MWh of generation; and to require retailers and wholesale industrial customers to purchase a specified volume of their electricity from large-scale renewable-sourced electricity or incur a penalty of AUD$65/MWh on any shortfall. The amendments reduced the annual targets for large-scale renewable sourced electricity down from 41,000 GWh in 2020 to 33,000 GWh in 2020, held constant at this level until 2030. It is estimated that this will require an additional 5,000-6,000 MW of new renewables capacity to be installed to add to the slightly more than 4,000 MW already operating. Since our Australian assets are fully contracted it is not expected that these amendments will have a significant impact on our operations.

Weather

Abnormal weather events can impact our operations and give rise to risks. In addition, normal year-over-year variations in wind, solar, water, and temperatures give rise to various levels of volume risk depending on the input fuel of each facility; events outside the design parameters of our facilities give rise to equipment risk; and fluctuations in temperatures can cause commodity price risk through impact on customer demand for heating or cooling. Refer to the Governance and Risk Management section of this MD&A for further discussion of each risk and our related management strategy.

During the past three years, some deviations from expected weather patterns have negatively impacted our annual financial results:

- the Southern Alberta flood of 2013 disrupted our hydro operations and caused us to invest in substantial repair work. Our losses have been largely covered through insurance,
- warm weather in Alberta in 2015 increased derates at our coal facilities due to its impact on the Sundance cooling ponds. These cooling ponds are susceptible to warm weather; however, we anticipate that decreased coal production and the retirement of Sundance Units 1 and 2 in the medium term will reduce the stress from such occurrence, and
- our Alberta mine was susceptible to significant rain starting in August of 2016, which resulted in several weeks of flooding and impacted our coal deliveries. We focused on improving drainage infrastructure and use of stockpiles to mitigate future risks.

Over the same period, other deviations have positively impacted our financial results, such as the cold temperatures in Eastern North America in the winter of 2014 that caused market volatility and benefitted our Energy Marketing Group.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

As part of our monitoring controls, long-range forecasts are prepared for each Cash Generating Unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide a criteria to evaluate adverse changes in operations. When indicators of impairment are present, we estimate a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets extending to the last planned asset retirement in 2073.

In 2016, we concluded that an indicator of possible impairment existed with respect to our U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section III below.

During 2016, uncertainty continued to exist within the province of Alberta regarding the government's previously announced Climate Leadership Plan and the future design parameters of the electricity market. Additionally, economic conditions, while more stable than in 2014 and 2015, contributed to continued over-supply conditions and depressed market prices. We assessed whether these factors presented an indicator of impairment for our Alberta Merchant CGU, and in consideration of the composition of this CGU and events arising during the latter part of 2016, which are more fully discussed below in I, determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, we did not perform an in-depth impairment analysis, but sensitivities associated with these factors were performed to confirm the continued existence of an adequate excess of estimated recoverable amount over net book value.

There was one impairment charge of $28 million (2015 - $2 million reversal) made during the year ended Dec. 31, 2016 as a result of the sale of our 51 per cent interest in the Wintering Hills merchant wind facility as discussed below in II.

I. Alberta Merchant CGU

In 2015, the Government of Alberta announced its Climate Leadership Plan ("CLP"), which broadly called for the phase-out of coal-generated electricity by 2030, and proposed the imposition of additional compliance obligations for GHG emissions in the province. In 2016, the Government of Alberta refined its approach to GHG by instituting a levy on carbon emissions in excess of defined limits, amounting to $20 per tonne in 2017 and $30 per tonne in 2018. At the federal level, the Canadian government announced its intention to implement a national price on GHG emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022.

On November 24, 2016, we entered into the OCA with the Government of Alberta to receive annual cash payments of approximately $37.4 million, net to us in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, we entered into an MOU on Nov. 24, 2016, with the purpose of collaborating and co-operating to advance objectives of the Alberta CLP. Specifically, the parties collaborated on initiatives that included:

- a move toward a capacity market, commencing 2021, compared to the current energy-only market. Under a capacity market, generators are compensated for their available capacity;
- development of a policy and to facilitate the economic conversion of some coal-fired generation to natural gas-fired generation in Alberta, including securing regulatory co-operation from the federal government; and
- development of supportive and enabling policy, including policy that addresses the value of carbon reductions in the generation of electricity from existing wind and hydro generation, the development of effective supporting mechanisms to ensure that existing renewables generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Government of Alberta and the Corporation and does not impose any obligations on, or constrain the discretion and authority of the Government of Alberta. The announcement of the intention to move to a capacity market is expected to impact the Alberta market mechanisms. The Government of Alberta has not provided further detail on the market rules or construct. The introduction of a capacity market to replace Alberta's current market structure could impact our determination of the Alberta Merchant CGU; however, there is not currently sufficient information from the Government of Alberta to determine if a change is required. We have not modified its previous conclusions on the determination of the Alberta Merchant CGU.

During the year, we monitored the potential impacts of the CLP and other announcements on the Alberta CGU. A sensitivity analysis on these estimates to assess potential impacts of the Alberta and federal government policies on the carbon levy and GHG emissions, as well as the impacts of the OCA and MOU. The analysis of the Alberta Merchant CGU, with its large merchant renewable fleet, resulted in no impairment in 2016.

II. Wintering Hills

On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. In connection with this sale, the Wintering Hills assets were accounted for as held for sale at December 31, 2016. As required, we assessed the assets for impairment prior to classifying them as held for sale. Accordingly, we have recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal.

III. U.S. Coal

We considered possible impairment at the U.S. Coal CGU, and again found that the fair value less costs to sell approximates the current carrying amount. We estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing our long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$22.68 to 45.65 per MWh
On-highway diesel fuel on coal shipments	US$1.69 to 2.09 per gallon
Discount rates	5.4 to 5.7 per cent

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

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

Centralia Gas

During 2014 we sold a portion of the assets of the Centralia gas facility to external counterparties and transferred other assets to other TransAlta facilities. The plant had been fully impaired and idled since 2010. As a result of the transaction, we recognized impairment reversals of $5 million and the plant's generating capacity has been removed from TransAlta's total owned capacity. In 2015, we reversed $2 million of previously impaired change as a result of additional recoveries. No further reversals or impairments were recorded in 2016.

Other Significant and Subsequent Events

Alberta Off-Coal Agreement

On Nov. 24, 2016, we announced that we entered into the OCA with the Government of Alberta on transition payments in exchange for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, we will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions in 2030. Other conditions include maintaining prescribed spending on investment and investment-related activities in Alberta, maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels), and maintaining spending on programs and initiatives to support the communities surrounding the plants, and the employees of the Corporation negatively impacted by the phase-out of coal generation and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. We claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, we announced that the independent arbitration panel confirmed our claim for force majeure relief. Accordingly, we reversed a provision of approximately $94 million. The buyer and the Balancing Pool are seeking to appeal or set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. We oppose these steps and believe they are without merit.

Memorandum of Understanding with the Government

In November 2016, we additionally reached an understanding with the Government of Alberta pursuant to an MOU to collaborate and co-operate in the development of a policy framework to facilitate the conversion of coal-fired generation to gas-fired generation, facilitate existing and new renewable electricity development through supportive and enabling policy, and ensure existing generation and new electricity generation are able to effectively participate in the recently announced capacity market to be developed for the province of Alberta. Specifically, the parties undertook to collaborate on, among other things:

- work to ensure existing incumbents and new electricity generation are able to effectively participate in capacity payment auctions to be established as part of the development of a capacity market,
- development of a policy environment to facilitate the economic and environmentally responsible conversion of some coal-fired generation to natural gas-fired generation in Alberta, including securing regulatory cooperation from the federal government, and
- development of supportive and enabling policy, including policy that addresses the value of carbon reductions in the generation of electricity from existing wind and hydro generation, the development of effective supporting mechanisms to ensure that existing renewables generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Government of Alberta and the Corporation and does not impose any obligations on, or constrain the discretion and authority of, the Government of Alberta.

Mississauga Cogeneration Facility New Contract

On Dec. 22, 2016, we announced that we had signed a Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") with the IESO for our Mississauga cogeneration facility (the "Mississauga Facility"). The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, we agreed to terminate effective Dec. 31, 2016, the Facility's pre-existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018.

The NUG Contract provides us stable monthly payments until Dec. 31, 2018, totalling approximately $209 million, reduced operational costs, and the ability to maintain operational flexibility to pursue opportunities for the Mississauga Facility to meet power market needs in northeastern Ontario.

As a result of the NUG Contract, we recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling $15 million. We also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. We released and recognized in earnings unrealized pre-tax losses of net $14 million from Accumulated Other Comprehensive Income ("AOCI") due to cash flow hedges de-designated for accounting purposes. The cash flow hedges were in respect of future gas purchases denominated in US dollars expected to occur between 2017 and 2018. In the fourth quarter of 2016, the forecasted gas consumption was no longer expected to occur, which resulted in the cumulative loss on the hedging instruments being released from AOCI and recognized in earnings.

Investment and Acquisition by TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Québec. The transaction was originally announced on Nov. 23, 2015.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30 and December 31, and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of $13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation through issuance of common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery. On Jan. 6, 2016, TransAlta Renewables declared a dividend increase of 5 per cent.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million through the issuance of a non-interest bearing loan payable to the Corporation.

Wintering Hills Sale

On Jan. 26, 2017, we announced the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. Proceeds from the sale will be used for general corporate purposes, including reducing our debt and funding future renewables growth. The sale closed March 1, 2017. We acquired the interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with our Poplar Creek cogeneration facility. As at Dec. 31, 2016, the assets are classified as held for sale, and were measured at the lower of carrying amount and fair value less costs to sell, resulting in an impairment charge of $28 million, included in the Wind and Solar segment. This arrangement provides us with near-term liquidity and increases our financial flexibility to pay down debt maturities.

Preferred Share Exchange

On Feb. 10, 2017, we announced that we would not proceed with the transaction previously announced Dec. 19, 2016 pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares.

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2016, to Dec. 31, 2015:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	251	Timing of receipts and payments, and non-recourse bond offerings
Trade and other receivables	136	Timing of customer receipts and seasonality of revenue, and current Mississauga facility recontracting receivable ($91 million)
Assets held for sale	61	Transfer of Wintering Hills wind facility from PP&E
Finance lease receivables (long term)	(56)	Unfavourable changes in foreign exchange rates ($12 million) and scheduled receipts ($56 million), partially offset by an increase due to completion of gas conversion work at the Solomon gas plant ($14 million)
Property, plant, and equipment, net	(349)	Depreciation for the period ($607 million), unfavourable changes in foreign exchange rates ($46 million), retirement of assets ($21 million), partially offset by additions ($358 million), revisions to decommissioning and restoration costs ($71 million), and transfer of Wintering Hills to assets held for sale ($61 million)
Intangible assets	(14)	Amortization ($38 million), partially offset by additions ($24 million)
Deferred income tax assets	(18)	Decreases in deductible temporary differences
Risk management assets (current and long term)	(61)	Unfavourable changes in foreign exchange rates and contract settlements, partially offset by favourable market price movements
Other assets	109	Mississauga facility recontracting long term receivable ($116 million)
Other	(10)	
Total decrease in assets	**49**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	79	Timing of payments and accruals
Credit facilities, long term debt, and finance lease obligations (including current portion)	(134)	Credit facility repayment ($315 million), repayment of long term debt ($88 million), and favourable effects of changes in foreign exchange rates ($67 million), partially offset by bond issuances ($362 million)
Decommissioning and other provisions (current and long term)	(55)	Keephills 1 provision reversal ($94 million) and liabilities settled ($59 million), partially offset by a decrease in risk-adjusted discount rates ($44 million)
Defined benefit obligation and other long term liabilities	(18)	Amortization of deferred revenue ($7 million) and actuarial gains ($8 million)
Deferred income tax liabilities	65	Mississauga recontracting and increase in taxable temporary differences
Risk management liabilities (current and long term)	(155)	Favourable market price movements and contract settlements
Equity attributable to shareholders	150	Net earnings ($169 million), issuance of common shares ($19 million), gains on cash flow hedges ($106 million), and changes in non-controlling interests in TransAlta Renewables ($26 million), partially offset by net losses on translating net assets of foreign operations ($53 million) and common and preferred share dividends ($110 million)
Non-controlling interests	123	Sale of economic interests to TransAlta Renewables, partially offset by distributions paid and payable to non-controlling interests
Other	(6)	
Total decrease in liabilities and equity	**49**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2016, compared to the years ended Dec. 31, 2015 and Dec. 31, 2014:

Year ended Dec. 31	2016	2015	Primary factors explaining change
Cash and cash equivalents, beginning of year	54	43	
Provided by (used in):			
Operating activities	744	432	Favourable change in non-cash working capital of $315 million
Investing activities	(327)	(573)	Lower additions to property, plant, and equipment ($118 million), a higher decrease in finance lease receivables ($33 million), and a decrease in our renewable asset acquisitions ($101 million)
Financing activities	(163)	149	Increase in repayments of borrowings under credit facilities ($533 million), lower issuance of long-term debt ($126 million), lower proceeds on the sale of non-controlling interest in a subsidiary ($242 million), higher distributions paid to subsidiaries' non-controlling interests ($52 million), and lower realized gains on financial instruments ($89 million), partially offset by lower dividends paid to common shareholders ($55 million) and lower repayment of long-term debt ($670 million).
Translation of foreign currency cash	(3)	3	
Cash and cash equivalents, end of year	305	54	

Year ended Dec. 31	2015	2014	Primary factors explaining change
Cash and cash equivalents, beginning of year	43	42	
Provided by (used in):			
Operating activities	432	796	Decrease in cash earnings of ($49 million) and an adverse change in non-cash working capital of ($315 million)
Investing activities	(573)	(292)	A decrease in proceeds on the sale of investment of ($224 million) and the acquisition of solar and wind assets for ($101 million)
Financing activities	149	(503)	Reduction in the net decrease in borrowings of ($500 million), an increase in proceeds on the sale of non-controlling interest in a subsidiary of ($275 million), and an increase in realized gains on financial instruments of ($52 million), partially offset by a decrease in net proceeds on the issuance of preferred shares of ($161 million)
Translation of foreign currency cash	3	-	
Cash and cash equivalents, end of year	54	43	

Unconsolidated Structured Entities or Arrangements

Disclosure is required of all unconsolidated structured entities or arrangements such as transactions, agreements, or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities, or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such unconsolidated structured entities or arrangements.

Guarantee Contracts

We have obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, construction projects, and purchase obligations. At Dec. 31, 2016, we provided letters of credit totalling $566 million (2015 - $575 million) and cash collateral of $77 million (2015 - $74 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities and decommissioning and other provisions.

Commitments

Contractual commitments are as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Natural gas, transportation, and other purchase contracts	40	13	6	5	5	100	**169**
Transmission	9	11	8	8	4	3	**43**
Coal supply and mining agreements(1)	163	48	49	51	52	472	**835**
Long-term service agreements	79	29	24	41	30	51	**254**
Non-cancellable operating leases(2)	7	7	7	7	7	68	**103**
Long-term debt(3)	623	959	461	460	63	1,745	**4,311**
Principal payments on finance lease obligations	16	14	10	8	6	19	**73**
Interest on long-term debt and finance lease obligations(4)	219	174	143	117	91	764	**1,508**
Growth	181	5	1	-	-	-	**187**
TransAlta Energy Bill	6	6	6	6	6	12	**42**
Total	**1,343**	**1,266**	**715**	**703**	**264**	**3,234**	**7,525**

As part of the TransAlta Energy Bill signed into law in the State of Washington and the subsequent MoA, we have committed to fund US$55 million over the remaining life of the U.S. Coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required.

I. Line Loss Rule Proceeding

TransAlta is participating in a line loss rule proceeding (the "LLRP") which is currently before the AUC. The AUC determined that it had the ability to retroactively adjust line loss rates beginning in 2006 and has directed the Alberta Electric System Operator (the "AESO"), among other actions, to perform such calculations. The various decisions by the AUC are subject to appeal and challenge. TransAlta may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP remains uncertain and the potential exposure, if any, cannot be calculated with any degree of certainty until the retroactive calculations are made available. The AESO expects retroactive calculations to be available mid-2017, at the earliest. As a result, no provision has been recorded. Certain PPAs for TransAlta's Alberta facilities provide for the pass through of these types of transmission charges to TransAlta's buyers.

(1) Commitments related to Sheerness and Genesee 3 may be impacted by the cessation of coal-fired emissions on or before Dec. 31, 2030.
(2) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.
(3) Excludes impact of derivatives.
(4) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.

Financial Instruments

Financial instruments are used for proprietary trading purposes and to manage our exposure to interest rates, commodity prices, and currency fluctuations, as well as other market risks. We currently use physical and financial swaps, forward sale and purchase contracts, futures contracts, foreign exchange contracts, interest rate swaps, and options to achieve our risk management objectives. Some of our physical commodity contracts have been entered into and are held for the purposes of meeting our expected purchase, sale, or usage requirements ("own use") and as such, are not considered financial instruments and are not recognized as a financial asset or financial liability. Other physical commodity contracts that are not held for normal purchase or sale requirements and derivative financial instruments are recognized on the Consolidated Statements of Financial Position and are accounted for using the fair value method of accounting. The initial recognition of fair value and subsequent changes in fair value can affect reported earnings in the period the change occurs if hedge accounting is not elected. Otherwise, changes in fair value will generally not affect earnings until the financial instrument is settled.

Some of our financial instruments and physical commodity contracts qualify for, and are recorded under, hedge accounting rules. The accounting for those contracts for which we have elected to apply hedge accounting depends on the type of hedge. Our financial instruments are categorized as fair value hedges, cash flow hedges, net investment hedges, or non-hedges. These categories and their associated accounting treatments are explained in further detail below.

For all types of hedges, we test for effectiveness at the end of each reporting period to determine if the instruments are performing as intended and hedge accounting can still be applied. The financial instruments we enter into are designed to ensure that future cash inflows and outflows are predictable. In a hedging relationship, the effective portion of the change in the fair value of the hedging derivative does not impact net earnings, while any ineffective portion is recognized in net earnings.

We have certain contracts in our portfolio that, at their inception, do not qualify for, or we have chosen not to elect to apply, hedge accounting. For these contracts, we recognize in net earnings mark-to-market gains and losses resulting from changes in forward prices compared to the price at which these contracts were transacted. These changes in price alter the timing of earnings recognition, but do not necessarily determine the final settlement amount received. The fair value of future contracts will continue to fluctuate as market prices change.

The fair value of derivatives traded by the Corporation that are not traded on an active exchange, or extend beyond the time period for which exchange-based quotes are available, are determined using valuation techniques or models.

Fair Value Hedges

Fair value hedges are used to offset the impact of changes in the fair value of fixed rate long-term debt caused by variations in market interest rates. We use interest rate swaps in our fair value hedges.

In a fair value hedge, changes in the fair value of the hedging instrument (an interest rate swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings. The carrying amount of long-term debt subject to the hedge is adjusted for losses or gains associated with the hedged risk, with the corresponding amounts recognized in net earnings. As a result, only the net ineffectiveness is recognized in net earnings.

Cash Flow Hedges

Cash flow hedges are categorized as project, foreign exchange, interest rate, or commodity hedges and are used to offset foreign exchange, interest rate, and commodity price exposures resulting from market fluctuations.

Foreign currency forward contracts are used to hedge foreign exchange exposures resulting from anticipated contracts and firm commitments denominated in foreign currencies, primarily related to capital expenditures.

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options are used primarily to offset the variability in future cash flows caused by fluctuations in electricity and natural gas prices. Foreign exchange forward contracts and cross-currency swaps are used to offset the exposures resulting from foreign-denominated long-term debt. Interest rate swaps are used to convert the fixed interest cash flows related to interest expense at debt to floating rates and vice versa.

In a cash flow hedge, changes in the fair value of the hedging instrument (a forward contract or financial swap, for example) are recognized in risk management assets or liabilities, and the related gains or losses are recognized in OCI. These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

When we do not elect hedge accounting, or when the hedge is no longer effective and does not qualify for hedge accounting, the gains or losses as a result of changes in prices, interest, or exchange rates related to these financial instruments are recorded in net earnings in the period in which they arise.

Net Investment Hedges

Foreign currency forward contracts and foreign-denominated long-term debt have historically been used to hedge exposure to changes in the carrying values of our net investments in foreign operations that have a functional currency other than the Canadian dollar. In late 2016 we modified our net investment hedging practices and are no longer using foreign currency forward contracts in our hedges. Our net investment hedges using U.S.-denominated debt remain effective and in place. Gains or losses on these instruments are recognized and deferred in OCI and reclassified to net earnings on the disposal of the foreign operation. We also manage foreign exchange risk by matching foreign-denominated expenses with revenues, such as offsetting revenues from our U.S. operations with interest payments on our US dollar debt.

Non-Hedges

Financial instruments not designated as hedges are used for proprietary trading and to reduce commodity price, foreign exchange, and interest rate risks. Changes in the fair value of financial instruments not designated as hedges are recognized in risk management assets or liabilities, and the related gains or losses are recognized in net earnings in the period in which the change occurs.

Fair Values

The majority of fair values for our project, foreign exchange, interest rate, commodity hedges, and non-hedge derivatives are calculated using adjusted quoted prices from an active market or inputs validated by broker quotes. We may enter into commodity transactions involving non-standard features for which market-observable data is not available. These transactions are defined under IFRS as Level III instruments. Level III instruments incorporate inputs that are not observable from the market, and fair value is therefore determined using valuation techniques. Fair values are validated by using reasonably possible alternative assumptions as inputs to valuation techniques, and any material differences are disclosed in the notes to the financial statements. At Dec. 31, 2016, Level III instruments had a net asset carrying value of $758 million. Refer to the Critical Accounting Policies and Estimates section of this MD&A for further details regarding valuation techniques. Our risk management profile and practices have not changed materially from Dec. 31, 2015, with the exception of the changes to our net investment hedge strategy, as discussed above and in the Governance and Risk Management section of this MD&A.

2017 Financial Outlook

For 2017, we expect our results to be slightly better than 2016 given the positive contribution from South Hedland, which is expected to be operational by mid-2017, and the receipt of the first coal transition payment from the Government of Alberta. The outlook also accounts for expected continuing weak power prices in Alberta, the Pacific Northwest, and the impact of lower priced power hedges in 2017. Approximately 85 per cent of our capacity in Alberta is contracted, either through power PPAs or financial contracts at an average price of $45 MWh to $50 MWh. Our performance next year will also be impacted by an increase in our fuel costs caused by a planned major outage to one of the large draglines at the Highvale Mine.

The following table outlines our expectation on key financial targets for 2017:

Measure	Target
Comparable EBITDA	$1,025 million to $1,135 million
Comparable FFO	$765 million to $855 million
Comparable FCF	$300 million to $365 million
Dividend	$0.16 per share annualized, 13 to 15 per cent payout of Comparable FCF

Operations

Availability

Availability of our coal fleet is expected to be in the range of 86 to 88 per cent in 2017. Availability of our other generating assets (gas, renewables) generally exceeds 95 per cent.

Fuel Costs

The cost to mine coal in Alberta is expected to increase due to a major outage of a dragline. Seasonal variations in coal costs at our Alberta mine are minimized through the application of standard costing. Coal costs for 2017, on a standard cost per tonne basis, are expected to be approximately 12 per cent higher than 2016 unit costs.

In the Pacific Northwest, our U.S. Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at U.S. Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost will increase slightly in 2017 primarily due to higher transportation costs.

Most of our generation from gas is sold under contract with pass-through provisions for fuel. For gas generation with no pass-through provision, we purchase natural gas from outside companies coincident with production, thereby minimizing our risk to changes in prices.

We closely monitor the risks associated with changes in electricity and input fuel prices on our future operations and, where we consider it appropriate, use various physical and financial instruments to hedge our assets and operations from such price risks.

Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted, and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2017 objective for Energy Marketing is for the segment to contribute between $70 million to $90 million in gross margin for the year.

Exposure to Fluctuations in Foreign Currencies

Our strategy is to minimize the impact of fluctuations in the Canadian dollar against the US dollar, and Australian dollar by offsetting foreign-denominated assets with foreign-denominated liabilities and by entering into foreign exchange contracts. We also have foreign-denominated expenses, including interest charges, which largely offset our net foreign-denominated revenues.

Net Interest Expense

Net interest expense for 2017 is expected to be higher than in 2016 largely due to lower capitalized interest. However, changes in interest rates and in the value of the Canadian dollar relative to the US dollar can affect the amount of net interest expense incurred.

Net Debt, Liquidity, and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.7 billion in liquidity including more than $300 million in cash. Our continued focus will be toward repositioning our capital structure and we expect to be well positioned to address the upcoming debt maturities in 2017 and 2018.

Capital Expenditures

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

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

	Total Project		2017	Target	
	Estimated spend	Spent to date[1]	Estimated spend	completion date	Details
Project					
South Hedland power project[2]	576	336	230 - 250	Q2 2017	150 MW combined-cycle power plant
Solomon load bank facility	5	2	3	Q1 2017	Installation of 20MW load bank facility required to support the operation of the Solomon power station
Transmission	Not applicable[3]		3	Ongoing	Regulated transmission that receives a return on investment
Total	**581**	**338**	**256 - 276**		

Cash required to fund the construction of the South Hedland power project is expected to be partially funded by proceeds from project financing and cash generated by our business.

(1) Represents amounts spent as of Dec. 31, 2016.

(2) Estimated project expenditures are AUD$553 million. Total estimated project expenditures are stated in CAD$ and includes estimated capital interest costs. The total estimated project expenditures may change due to fluctuations in foreign exchange rates.

(3) Transmission projects are aggregated and develop on an ongoing basis. Consequently, discrete project expenditures are not available.

A significant portion of our sustaining and productivity capital is planned major maintenance, which includes inspection, repair and maintenance of existing components, and the replacement of existing components. Planned major maintenance costs are capitalized as part of PP&E and are amortized on a straight-line basis over the term until the next major maintenance event. It excludes amounts for day-to-day routine maintenance, unplanned maintenance activities, and minor inspections and overhauls, which are expensed as incurred.

Our estimate for total sustaining and productivity capital is allocated among the following:

Category	Description	Spent in 2015	Spent in 2016	Expected spend in 2017
Routine capital[(1)]	Capital required to maintain our existing generating capacity	101	83	85 - 90
Planned major maintenance	Regularly scheduled major maintenance	162	148	125 - 130
Mine capital	Capital related to mining equipment and land purchases	25	23	30 - 35
Finance leases	Payments on finance leases	13	16	20 - 25
Total sustaining capital excluding flood-recovery capital		**301**	**270**	**260 - 280**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	4	2	-
Total sustaining capital		**305**	**272**	**260 - 280**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	6	8	10 - 15
Total sustaining and productivity capital		**311**	**280**	**270 - 295**

Significant planned major outages for 2017 include the following:

- four major outages in which two relate to our partners, and a major outage to draglines at our Canadian Coal segment,
- three major outages in our Canadian Gas segment related to our Sarnia and Windsor facilities,
- one major outage in our Alberta Hydro segment and distributed planned maintenance expenditures across the entire fleet, and
- distributed expenditures across our wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for U.S. Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2017:

	Coal	Gas and Renewables	Total
GWh lost	895 - 905	200 - 230	1,095 - 1,135

Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities, existing liquidity, and capital raised from our contracted cash flows. We have access to approximately $1.7 billion in liquidity, if required. The funds required for committed growth, sustaining capital, and productivity projects are not expected to be significantly impacted by the current economic environment.

(1) Includes hydro life extension expenditures.

Sustainable Development Targets

Our 2017 and longer-term sustainability targets support the long-term success of our business. Targets are set in line with business unit goals to manage key areas of concern for stakeholders and ultimately improve our environmental and social performance in these areas. We continue to evolve and adapt targets to focus on anticipated key areas of materiality to stakeholders. Targets are outlined below:

	Human and Intellectual	Annual Performance Status
1. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.50	33 per cent improvement over 2016 target of 0.75
2. Manage employee turnover	Maintain voluntary turnover percentage under eight per cent	Consistent with 2016 target, we seek to maintain voluntary turnover under 8 per cent as this is considered a healthy amount of turnover
3. Support employee development	Continue development plans for all high-potential employees at the top three levels of the organization	Consistent with 2016 target, ongoing leadership development

	Natural	Annual Performance Status
4. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 11	15 per cent improvement over 2016 target (13)
5. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 74 acres/year	Consistent with 2016 target (74 acres)
6. Utilize coal by-product	Sell a minimum of two million tonnes of coal byproduct materials during the period 2015 to 2017	70 per cent achieved (on a target to meet 2 million tonnes in 2017)
7. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030	Consistent with 2016 (long-term target)
8. Reduce GHG emissions	Our goal, in line with a commitment to the UN Sustainable Development Goals (SDGs), is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels	Revised baseline to align with COP21 commitments and target aligned with UN Sustainable Development Goals
	Our goal, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming, is to reduce our total greenhouse gas emissions in 2030 to 60 per cent below 2015 levels	Revised baseline to align with COP21 commitments; target aligned with Science Based Targets Initiative and prevention of two degrees Celsius of global warming; and target aligned with UN SDGs

	Social and Relationship	Annual Performance Status
9. Support youth education with community investment	Approximately $0.75 million of community investment spending will be directed to supporting youth education	Revision from 2015, which was 50% of total community
10. Increase internal best practice Aboriginal engagement awareness	Develop an engagement and consultation best practices document for project planning and development as a guide for employees to work with indigenous communities and stakeholders	New target

	Comprehensive	Annual Performance Status
10. Transition from coal to gas-fired and renewable generation	Continue negotiations with the Government of Alberta, using a principles based approach, to ensure we have regulation certainty and the capacity needed to invest in clean power.	New target

Governance and Risk Management

Our business activities expose us to a variety of risks and opportunities including, but not limited to, regulatory changes, rapidly changing market dynamics, and increased volatility in our key commodity markets. Our goal is to manage these risks and opportunities so that we are in position to develop our business and achieve our goals while remaining reasonably protected from an unacceptable level of risk or financial exposure. We use a multilevel risk management oversight structure to manage the risks and opportunities arising from our business activities, the markets in which we operate, and the political environments and structures with which we interface.

Governance

The key elements of our governance practices are:

- employees, management and the Board are committed to ethical business conduct, integrity, and honesty,
- we have established key policies and standards to provide a framework for how we conduct our business,
- the Chair of our Board and all directors, other than our Chief Executive Officer ("CEO") are independent,
- the Board is comprised of individuals with a mix of skills, knowledge, and experience that are critical for our business and our strategy,
- the effectiveness of the Board is achieved through annual evaluations and continuing education of our directors, and
- our management and Board facilitate and foster an open dialogue with shareholders and community stakeholders.

Commitment to ethical conduct is the foundation of our corporate governance model. We have adopted the following codes of conduct to guide our business decisions and everyday business activities:

- Corporate Code of Conduct, which applies to all employees and officers of TransAlta and its subsidiaries,
- Directors' Code of Conduct,
- Finance Code of Ethics, which applies to all financial employees of the Corporation, and
- Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our codes of conduct outline the standards and expectations we have for our employees, officers, and directors with respect to the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, conflicts of interest, respect in the workplace, social responsibility, privacy, compliance with laws, insider trading, environment, health and safety, and our commitment to ethical and honest conduct. Our Corporate Code of Conduct goes beyond the laws, rules, and regulations that govern our business in the jurisdictions in which we operate; it outlines the principal business practices with which all employees must comply.

Our employees, officers, and directors are reminded annually about the importance of ethics and professionalism in their daily work, and must certify annually that they have reviewed and understand their responsibilities as set forth in the respective codes of conduct. This certification also requires our employees, officers, and directors to acknowledge that they have complied with the standards set out in the respective code during the last calendar year.

The Board provides stewardship of the Corporation and ensures that the Corporation establishes key policies and procedures for the identification, assessment, and management of principal risks and strategic plans. The Board monitors and assesses the performance and progress of the Corporation's goals through candid and timely reports from the CEO and the senior management team. We have also established an annual evaluation process whereby our directors are provided with an opportunity to evaluate the Board, Board committees, individual directors, and the chair's performance.

In order to allow the Board to establish and manage the financial, environmental, and social elements of our governance practices, the Board has established the Audit and Risk Committee ("ARC"), the GEC, and the Human Resources Committee (the "HRC").

The ARC, consisting of independent members of the Board, provides assistance to the Board in fulfilling its oversight responsibility relating to the integrity of our financial statements and the financial reporting process; the systems of internal accounting and financial controls; the internal audit function; the external auditors' qualifications and terms and conditions of appointment, including remuneration; independence; performance and reports; and the legal and risk compliance programs as established by management and the Board. The ARC approves our Commodity and Financial Exposure Management policies and reviews quarterly Enterprise Risk Management reporting.

The GEC is responsible for developing and recommending to the Board a set of corporate governance principles applicable to the Corporation and for monitoring the compliance with these principles. The GEC is also responsible for Board recruitment and for the nomination of directors to the Board and its committees. In addition, the GEC assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations and public policy changes and the establishment and adherence to environmental, health and safety practices, procedures, and policies. The GEC also receives an annual report on the annual Corporate Code of Conduct certification process.

In regards to overseeing and seeking to ensure that the Corporation consistently achieves strong environment, health, and safety ("EH&S") performance, the GEC undertakes a number of actions that include: (i) receiving regular reports from management regarding environmental compliance, trends, and TransAlta's responses; (ii) receiving reports and briefings on management's initiatives with respect to changes in climate change legislation, policy developments as well as other draft initiatives and the potential impact such initiatives may have on our operations; (iii) assessing the impact of the GHG policies implementation and other legislative initiatives on the Corporation's business; (iv) reviewing with management the EH&S policies of the Corporation; (v) reviewing with management the health and safety practices implemented within the Corporation, as well as the evaluation and training processes put in place to address problem areas; (vi) receiving reports from management on the near-miss reporting program and discussing with management ways to improve the EH&S processes and practices; and (vi) reviewing the effectiveness of our response to EH&S issues and any new initiatives put in place to further improve the Corporation's EH&S culture.

The HRC is empowered by the Board to review and approve key compensation and human resources policies of the Corporation that are intended to attract, recruit, retain, and motivate employees of the Corporation. The HRC also makes recommendations to the Board regarding the compensation of the Corporation's executive officers, including the review and adoption of equity-based incentive compensation plans, the adoption of human resources policies that support human rights and ethical conduct, and the review and approval of executive management succession and development plans.

The responsibilities of other stakeholders within our risk management oversight structure are described below:

The CEO and senior management review key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity and Compliance Risk Committee, and weekly by the Managing Director Commodity Risk, the commercial managing directors in Trading and Marketing, and the Senior Vice-President Trading and Marketing.

The Investment Committee is chaired by our Chief Financial Officer and is comprised of the CEO, Chief Financial Officer, Chief Legal and Compliance Officer and Corporate Secretary, and Chief Investment Officer. It reviews and approves all major capital expenditures including growth, productivity, life extensions, and major coal outages. Projects that are approved by the committee will then be put forward for approval by the Board, if required.

The Commodity Risk & Compliance Committee is chaired by our Chief Financial Officer and is comprised of the Chief Financial Officer, Chief Legal and Compliance Officer and Senior Vice President, Energy Marketing. It oversees the risk and compliance program in trading and ensures that this program is adequately resourced to monitor trading operations from a risk and compliance perspective. It also ensures the existence of appropriate controls, processes, systems and procedures to monitor adherence to policy.

TransAlta is listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange and is subject to the governance regulations, rules, and standards applicable under both exchanges. Our corporate governance practices meet the following governance rules of the TSX and Canadian Securities Administrators: (i) Multilateral Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings; (ii) Multilateral Instrument 52-110 - Audit Committees; (iii) National Policy 58-201 - Corporate Governance Guidelines; and (iv) National Instrument 58-101 - Disclosure of Corporate Governance

Practices. As a "foreign private issuer" under U.S. securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our management proxy circular.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

We strive to foster beliefs and actions that are true to, and respectful of, our many stakeholders. We do this by investing in communities where we live and work, operating and growing sustainably, putting safety first, and being responsible to the many groups and individuals with whom we work.

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a code of conduct on an annual basis.

Reporting

On a regular basis, residual risk exposures are reported to key decision makers including the Board, senior management, and the Commodity Risk & Compliance Committee. Reporting to this committee includes analysis of new risks, monitoring of status to risk limits, review of events that can affect these risks, and discussion and review of the status of actions to minimize risks. This quarterly reporting provides for effective and timely risk management and oversight.

Whistleblower System

We have a process in place where employees, shareholders, or other stakeholders may anonymously report any potential ethical concerns. These concerns can be submitted confidentially and anonymously, either directly to the ARC or to TransAlta's Ethics Helpline. All complaints are investigated and the ARC receives a report at every scheduled committee meeting on all findings. If the findings are urgent, they will be reported to the Chair of the Board immediately.

Value at Risk and Trading Positions

Value at risk ("VaR") is one of the primary measures used to manage our exposure to market risk resulting from commodity risk management activities. VaR is calculated and reported on a daily basis. This metric describes the potential change in the value of our trading portfolio over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations.

VaR is a commonly used metric that is employed by industry to track the risk in commodity risk management positions and portfolios. Two common methodologies for estimating VaR are the historical variance/covariance and Monte Carlo approaches. We estimate VaR using the historical variance/covariance approach. An inherent limitation of historical variance/covariance VaR is that historical information used in the estimate may not be indicative of future market risk. Stress tests are performed periodically to measure the financial impact to the trading portfolio resulting from potential market events, including fluctuations in market prices, volatilities of those prices, and the relationships between those prices. We also employ additional risk mitigation measures. VaR at Dec. 31, 2016, associated with our proprietary commodity risk management activities was $2 million (2015 - $5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future results and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other.

For some risk factors we show the after-tax effect on net earnings of changes in certain key variables. The analysis is based on business conditions and production volumes in 2016. Each item in the sensitivity analysis assumes all other potential variables are held constant. While these sensitivities are applicable to the period and the magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances, or for a greater magnitude of changes. The changes in rates should also not be assumed to be proportionate to earnings in all instances.

Volume Risk

Volume risk relates to the variances from our expected production. For example, the financial performance of our Hydro, Wind, and Solar operations is partially dependent upon the availability of their input resources in a given year. Where we are unable to produce sufficient quantities of output in relation to contractually specified volumes, we may be required to pay penalties or purchase replacement power in the market.

We manage volume risk by:

- actively managing our assets and their condition in order to be proactive in plant maintenance so that our plants are available to produce when required;
- monitoring water resources throughout Alberta to the best of our ability and optimizing this resource against real-time electricity market opportunities;
- placing our facilities in locations that we believe to have adequate resources to generate electricity to meet the requirements of our contracts. However, we cannot guarantee that these resources will be available when we need them or in the quantities that we require; and
- diversifying our fuels and geography as one way of mitigating regional or fuel-specific events.

The sensitivity of volumes to our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Availability/production	1	10

Generation Equipment and Technology Risk

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

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

We manage our generation equipment and technology risk by:

- operating our generating facilities within defined and proven operating standards that are designed to maximize the availability of our generating facilities for the longest period of time,
- performing preventive maintenance on a regular basis,
- adhering to a comprehensive plant maintenance program and regular turnaround schedules,
- adjusting maintenance plans by facility to reflect the equipment type and age,
- having sufficient business interruption coverage in place in the event of an extended outage,
- having force majeure clauses in our thermal and other PPAs and other long-term contracts,
- using proven technology in our generating facilities,
- monitoring technological advances and evaluating their impact upon our existing generating fleet and related maintenance programs,
- negotiating strategic supply agreements with selected vendors to ensure key components are available in the event of a significant outage,
- entering into long-term arrangements with our strategic supply partners to ensure availability of critical spare parts, and
- developing a long-term asset management strategy with the objective of maximizing the life cycles of our existing facilities and/or replacing of selected generating assets.

Commodity Price Risk

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

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

- entering into long-term contracts that specify the price at which electricity, steam, and other services are provided,
- maintaining a portfolio of short-, medium-, and long-term contracts to mitigate our exposure to short-term fluctuations in commodity prices,
- purchasing natural gas coincident with production for merchant plants so spot market spark spreads are adequate to produce and sell electricity at a profit, and
- ensuring limits and controls are in place for our proprietary trading activities.

In 2016, we had approximately 88 per cent (2015 - 90 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned plant outage or other similar event, however, we are exposed to changes in electricity prices on purchases of electricity from the market to fulfil our supply obligations under these short- and long-term contracts.

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

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

In 2016, 79 per cent (2015 - 66 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2015 - 100 per cent) of our purchased coal costs were contractually fixed.

The sensitivities of price changes to our net earnings, assuming production consistent with 2016 and applying the contractual profile in place at Dec. 31, 2016, are shown below:

Factor	Increase or decrease	Approximate impact on net earnings and cash flow
Electricity price - Canada	$ 1.00/MWh	2
Electricity price - U.S.	US$ 1.00/MWh	2
Natural gas price	$ 0.10/GJ	1

Actual variations in net earnings can vary from calculated sensitivities and may not be linear due to optimization opportunities, co-dependencies and cost mitigations, production, availability, and other factors.

Coal Supply Risk

Having sufficient fuel available when required for generation is essential to maintaining our ability to produce electricity under contracts and for merchant sale opportunities. At our coal-fired plants, input costs, such as diesel, tires, the price and availability of mining equipment, the volume of overburden removed to access coal reserves, rail rates, and the location of mining operations relative to the power plants are some of the exposures in our operations. Additionally, the ability of the mines to deliver coal to the power plants can be impacted by weather conditions and labour relations. At U.S. Coal, interruptions at our supplier's mine, the availability of trains to deliver coal, and the financial viability of our coal suppliers could affect our ability to generate electricity.

We manage coal supply risk by:

- ensuring that the majority of the coal used in electrical generation in Alberta is from reserves permitted through coal rights we have purchased or for which we have long-term supply contracts, thereby limiting our exposure to fluctuations in the supply of coal from third parties,
- using longer-term mining plans to ensure the optimal supply of coal from our mines,
- sourcing the majority of the coal used at U.S. Coal under a mix of short-, medium-, and long-term contracts and from multiple mine sources to ensure sufficient coal is available at a competitive cost,
- contracting sufficient trains to deliver the coal requirements at U.S. Coal,
- ensuring coal inventories on hand at Canadian Coal and U.S. Coal are at appropriate levels for usage requirements,
- ensuring efficient coal handling and storage facilities are in place so that the coal being delivered can be processed in a timely and efficient manner,
- monitoring and maintaining coal specifications, carefully matching the specifications mined with the requirements of our plants,
- monitoring the financial viability of U.S. coal suppliers, and
- hedging diesel exposure in mining and transportation costs.

Environmental Compliance Risk

Environmental compliance risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada (including as set forth in the Alberta Climate Leadership Plan) and the U.S. We anticipate continued and growing scrutiny by investors relating to sustainability performance. These changes to regulations may affect our earnings by reducing the operating life of generating facilities, imposing additional costs on the generation of electricity, such as emission caps or tax, requiring additional capital investments in emission capture technology, or requiring us to invest in offset credits. It is anticipated that these compliance costs will increase due to increased political and public attention to environmental concerns.

We manage environmental compliance risk by:

- seeking continuous improvement in numerous performance metrics such as emissions, safety, land and water impacts, and environmental incidents,
- having an International Organization for Standardization and Occupational Health and Safety Assessment Series-based environmental health and safety management system in place that is designed to continuously improve performance,
- committing significant experienced resources to work with regulators in Canada and the U.S. to advocate that regulatory changes are well designed and cost effective,
- developing compliance plans that address how to meet or surpass emission standards for GHGs, mercury, SO_2, and NO_x, which will be adjusted as regulations are finalized,
- purchasing emission reduction offsets,
- investing in renewable energy projects, such as wind, solar, and hydro generation, and
- incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

We strive to be in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to the GEC.

Credit Risk

Credit risk is the risk to our business associated with changes in the creditworthiness of entities with which we have commercial exposures. This risk results from the ability of a counterparty to either fulfil its financial or performance obligations to us or where we have made a payment in advance of the delivery of a product or service. The inability to collect cash due to us or to receive products or services may have an adverse impact upon our net earnings and cash flows.

We manage our exposure to credit risk by:

- establishing and adhering to policies that define credit limits based on the creditworthiness of counterparties, contract term limits, and the credit concentration with any specific counterparty,
- requiring formal sign-off on contracts that include commercial, financial, legal, and operational reviews,
- requiring security instruments, such as parental guarantees, letters of credit, and cash collateral that can be collected if a counterparty fails to fulfil its obligation or goes over its limits, and
- reporting our exposure using a variety of methods that allow key decision-makers to assess credit exposure by counterparty. This reporting allows us to assess credit limits for counterparties and the mix of counterparties based on their credit ratings.

If established credit exposure limits are exceeded, we take steps to reduce this exposure, such as by requesting collateral, if applicable, or by halting commercial activities with the affected counterparty. However, there can be no assurances that we will be successful in avoiding losses as a result of a contract counterparty not meeting its obligations.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2015. We had no material counterparty losses in 2016. We continue to keep a close watch on changes and trends in the market and the impact these changes could have on our energy trading business and hedging activities, and will take appropriate actions as required, although no assurance can be given that we will always be successful.

The following table outlines our maximum exposure to credit risk without taking into account collateral held or right of set-off, including the distribution of credit ratings, as at Dec. 31, 2016:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables(1)	92	8	100	703
Long-term finance lease receivables(2)	36	64	100	719
Risk management assets(1)	100	-	100	1,034
Total				2,456

The maximum credit exposure to any one customer for commodity trading operations, including the fair value of open trading positions net of any collateral held, is $14 million (2015 - $44 million).

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

(2) We have one non-investment grade customer whose outstanding balance accounted for $445 million (Dec. 31, 2015 - $446 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

Currency Rate Risk

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

We manage our currency rate risk by establishing and adhering to policies that allow for both designated hedges and economic hedges and include:

- hedging our net investments in U.S. operations using U.S.-denominated debt,
- entering into forward foreign exchange contracts to hedge future foreign denominated expenditures including our U.S.-denominated debt that is outside the net investment portfolio, and
- hedging our expected foreign operating cash flows. Our target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year, and 30 per cent in the fourth year. The U.S. exposure will be managed with a combination of interest expense on our U.S.-denominated debt and forward foreign exchange contracts; the Australian exposure will be managed with forward foreign exchange contracts.

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

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	$0.04	12

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to engage in trading and hedging activities, capital projects, debt refinancing and payment of liabilities, capital structure, and general corporate purposes. Investment grade credit ratings support these activities and provide a more reliable and cost-effective means to access capital markets through commodity and credit cycles. Changes in credit ratings may also affect our ability and/or the cost of establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment. Counterparties enter into certain electricity and natural gas purchase and sale contracts for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these contracts require the counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may challenge our ability to enter into these contracts or any ordinary course contract, decrease the credit limits granted, and increase the amount of collateral that may have to be provided. Certain existing contracts contain credit rating contingent clauses, that, when triggered, automatically increase costs under the contract or require additional collateral to be posted. Where the contingency is based on the lowest single rating, a one-level downgrade from a credit rating agency with an originally higher rating may not, however, trigger additional direct adverse impact.

We are focused on strengthening our financial position and flexibility and achieving stable investment grade credit ratings with rating agencies. Credit ratings issued for TransAlta, as well as the corresponding rating agency outlooks, are set out in the Financial Capital section of this MD&A. Credit ratings are subject to revision or withdrawal at any time by the rating organization, and there can be no assurance that TransAlta's credit ratings and the corresponding outlook will not be changed, resulting in the adverse possible impacts identified above.

As at Dec. 31, 2016, we have liquidity of $1.7 billion comprised of amounts not drawn under our committed credit facilities and cash on hand, and foresee no current need to draw down on this liquidity in 2017.

We manage liquidity risk by:

- monitoring liquidity on trading positions,
- preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital,
- reporting liquidity risk exposure for commodity risk management activities on a regular basis to the Commodity Risk & Compliance Committee, senior management, and the ARC,
- maintaining investment grade credit ratings; and
- maintaining sufficient undrawn committed credit lines to support potential liquidity requirements.

Interest Rate Risk

Changes in interest rates can impact our borrowing costs and the capacity revenues we receive from our Alberta PPA plants. Changes in our cost of capital may also affect the feasibility of new growth initiatives.

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

- employing a combination of fixed and floating rate debt instruments, and
- monitoring the mixture of floating and fixed rate debt and adjusting where necessary to ensure a continued efficient mixture of these types of debt.

At Dec. 31, 2016, approximately six per cent (2015 - nine per cent) of our total debt portfolio was subject to changes in floating interest rates through a combination of floating rate debt and interest rate swaps.

The sensitivity of changes in interest rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Interest rate	0.15	-

Project Management Risk

On capital projects, we face risks associated with cost overruns, delays, and performance.

We manage project risks by:

- ensuring all projects are reviewed to see that established processes and policies are followed, risks have been properly identified and quantified, input assumptions are reasonable, and returns are realistically forecasted prior to senior management and Board of Directors approvals,
- using consistent and disciplined project management methodologies and processes,
- performing detailed analysis of project economics prior to construction or acquisition and by determining our asset contracting strategy to ensure the right mix of contracted and merchant capacity prior to commencement of construction,
- partnering with those who have previously been able to deliver projects economically and on budget;
- developing and following through with comprehensive plans that include critical paths identified, key delivery points, and backup plans,
- managing project closeouts so that any learnings from the project are incorporated into the next significant project;
- fixing the price and availability of the equipment, foreign currency rates, warranties, and source agreements as much as is economically feasible prior to proceeding with the project, and
- entering into labour agreements to provide security around cost and productivity.

Human Resource Risk
Human resource risk relates to the potential impact upon our business as a result of changes in the workplace. Human resource risk can occur in several ways:

- potential disruption as a result of labour action at our generating facilities,
- reduced productivity due to turnover in positions,
- inability to complete critical work due to vacant positions,
- failure to maintain fair compensation with respect to market rate changes, and
- reduced competencies due to insufficient training, failure to transfer knowledge from existing employees, or insufficient expertise within current employees.

We manage this risk by:

- monitoring industry compensation and aligning salaries with those benchmarks,
- using incentive pay to align employee goals with corporate goals,
- monitoring and managing target levels of employee turnover, and
- ensuring new employees have the appropriate training and qualifications to perform their jobs.

In 2016, 53 per cent (2015 - 54 per cent) of our labour force was covered by 11 (2015 - 11) collective bargaining agreements. In 2016, five (2015 - two) agreements were renegotiated. We anticipate the successful negotiation of five collective agreements in 2017.

Regulatory and Political Risk
Regulatory and political risk is the risk to our business associated with potential changes to the existing regulatory structures and the political influence upon those structures. This risk can come from market regulation and re-regulation, increased oversight and control, structural or design changes in markets, or other unforeseen influences. Market rules are often dynamic and we are not able to predict whether there will be any material changes in the regulatory environment or the ultimate effect of changes in the regulatory environment on our business. This risk includes, among other things, uncertainties associated with the development of capacity markets for electricity in the provinces of Alberta and Ontario, uncertainties associated with the development of carbon pricing policies, the qualification of our renewable facilities in Alberta to the generation of tradable GHG allowances as part of the transition from the Specified Gas Emitters Regulation to new regulation to be formulated to give effect to the Alberta Climate Leadership Plan in 2018, as well as the influence of regulation on the value of allowances or credits generated.

We manage these risks systematically through our Legal and Regulatory groups and our Compliance program, which is reviewed periodically to ensure its effectiveness. We work with governments, regulators, electricity system operators, and other stakeholders to resolve issues as they arise. We are actively monitoring changes to market rules and market design, and we engage in market-sponsored stakeholder engagement processes. Through these and other avenues, we engage in advocacy and policy discussions at a variety of levels. These stakeholder negotiations have allowed us to engage in proactive discussions with governments over the longer term.

International investments are subject to unique risks and uncertainties relating to the political, social, and economic structures of the respective country and such country's regulatory regime. We mitigate this risk through the use of non-recourse financing and insurance.

Transmission Risk
Access to transmission lines and transmission capacity for existing and new generation are key in our ability to deliver energy produced at our power plants to our customers. The risks associated with the aging existing transmission infrastructure in markets in which we operate continue to increase because new connections to the power system are consuming transmission capacity quicker than it is being added by new transmission developments.

Reputation Risk
Our reputation is one of our most valued assets. Reputation risk relates to the risk associated with our business because of changes in opinion from the general public, private stakeholders, governments, and other entities.

We manage reputation risk by:
- striving as a neighbour and business partner in the regions where we operate to build viable relationships based on mutual understanding leading to workable solutions with our neighbours and other community stakeholders,
- clearly communicating our business objectives and priorities to a variety of stakeholders on a routine basis,
- maintaining positive relationships with various levels of government,
- pursuing sustainable development as a longer-term corporate strategy,
- ensuring that each business decision is made with integrity and in line with our corporate values,
- communicating the impact and rationale of business decisions to stakeholders in a timely manner, and
- maintaining strong corporate values that support reputation risk management initiatives.

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

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

We take measures to secure our infrastructure against potential cyber-attacks that may damage our infrastructure, systems and data. Our cyber security program aligns with industry best practices to ensure that a holistic approach to security is maintained. We have implemented security controls to help secure our data and business operations, including access control measures, intrusion detection and prevention systems, logging and monitoring of network activities, and implementing policies and procedures to ensure the secure operations of the business.

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

General Economic Conditions
Changes in general economic conditions impact product demand, revenue, operating costs, the timing and extent of capital expenditures, the net recoverable value of PP&E, financing costs, credit and liquidity risk, and counterparty risk.

Income Taxes
Our operations are complex and located in several countries. The computation of the provision for income taxes involves tax interpretations, regulations, and legislation that are continually changing. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by IFRS, based on all information currently available.

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

The sensitivity of changes in income tax rates upon our net earnings is shown below:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Tax rate	1	3

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

Other Contingencies
We maintain a level of insurance coverage deemed appropriate by management. There were no significant changes to our insurance coverage during renewal of the insurance policies on December 31. Our insurance coverage may not be available in the future on commercially reasonable terms. There can be no assurance that our insurance coverage will be fully adequate to compensate for potential losses incurred. In the event of a significant economic event, the insurers may not be capable of fully paying all claims.

Critical Accounting Policies and Estimates

The selection and application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules and guidance have changed. Accounting rules generally do not involve a selection among alternatives, but involve an implementation and interpretation of existing rules and the use of judgment relative to the circumstances existing in the business. Every effort is made to comply with all applicable rules on or before the effective date, and we believe the proper implementation and consistent application of accounting rules is critical.

However, not all situations are specifically addressed in the accounting literature. In these cases, our best judgment is used to adopt a policy for accounting for these situations. We draw analogies to similar situations and the accounting guidelines governing them, consider foreign accounting standards, and consult with our independent auditors about the appropriate interpretation and application of these policies. Each of the critical accounting policies involves complex situations and a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our consolidated financial statements.

Our significant accounting policies are described in Note 2 to our audited consolidated financial statements within this Annual Report. The most critical of these policies are those related to revenue recognition, financial instruments, valuation of PP&E and associated contracts, project development costs, useful life of PP&E, valuation of goodwill, leases, income taxes, employee future benefits, decommissioning and restoration provisions, and other provisions. Each policy involves a number of estimates and assumptions to be made about matters that are uncertain at the time the estimate is made. Different estimates, with respect to key variables used for the calculations, or changes to estimates, could potentially have a material impact on our financial position or results of operations.

We have discussed the development and selection of these critical accounting estimates with our ARC and our independent auditors. The ARC has reviewed and approved our disclosure relating to critical accounting estimates in this MD&A.

These critical accounting estimates are described as follows:

Revenue Recognition

The majority of our revenues are derived from the sale of physical power, leasing of power facilities, and from commodity risk management activities.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each of these components is recognized upon output, delivery, or satisfaction of contractually specific targets. Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each MWh produced and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where we retain the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above.

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, and futures contracts and options, to earn trading revenues and to gain market information. These derivatives are accounted for using fair value accounting when hedge accounting is not applied. The initial recognition of fair value and subsequent changes in fair value affect reported earnings in the period the change occurs. The fair values of instruments that remain open at the end of a reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities.

The determination of the fair value of commodity risk management contracts and derivative instruments is complex and relies on judgments concerning future prices, volatility, and liquidity, among other factors. Some of our derivatives are not traded on an active exchange or extend beyond the time period for which exchange-based quotes are available, requiring us to use internal valuation techniques or models.

Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for instruments in active markets to which we have access. In the absence of an active market, we determine fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, we look primarily to external readily observable market inputs. However, if not available, we use inputs that are not based on observable market data.

Level Determinations and Classifications

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access. In determining Level I fair values, we use quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials. Our commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

Level III

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

We may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices. We also have various contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

We have a Commodity Exposure Management Policy, which governs both the commodity transactions undertaken in our proprietary trading business and those undertaken to manage commodity price exposures in our generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

The effect of using reasonably possible alternative assumptions as inputs to valuation techniques from which the Level III commodity risk management fair values are determined at Dec. 31, 2016, is an estimated total upside of $93 million (2015 - $156 million upside) and total downside of $89 million (2015 - $211 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $75 million upside (2015 - $125 million upside) and $69 million downside (2015 - $186 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$24 to US$40 for the period from 2019 to 2025, while the remaining amounts account for the rest of the portfolio. The variable volumes are stressed up and down one standard deviation from historically available production data. Prices are stressed for longer-term deals where there are no liquid market quotes using various internal and external forecasting sources to establish a high and a low price range.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that a PP&E or intangible asset is impaired. Impairment exists when the carrying amount of the asset or CGU to which it belongs exceeds its recoverable amount, which is the higher of fair value less costs of disposal and value in use.

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used or in our overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where we are not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

Our operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the PP&E or CGU to which it belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, and transmission capacity or constraints for the remaining life of the facilities. Appropriate discount rates reflecting the risks specific to the asset under review are used in the assessments. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs, or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. We evaluate the market design, transmission constraints, and the contractual profile of each facility, as well as our commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. We evaluate synergies with regard to opportunities from combined talent and technology, functional organization, and future growth potential, and we consider our own performance measurement processes in making this determination.

As a result of our review in 2016 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Refer to the Asset Impairment Charges and Reversals section of this MD&A for further details.

Impairment charges can be reversed in future periods if circumstances improve. No assurances can be given if any reversal will occur or the amount or timing of any such reversal.

Project Development Costs

Deferred project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized in operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to us, at which time the costs incurred subsequently are included in PP&E or investments. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. A component is a tangible asset that can be separately identified as an asset and is expected to provide a benefit of greater than one year. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E and depreciation rates used are reviewed at least annually to ensure they continue to be appropriate.

In 2016, total depreciation and amortization expense was $664 million (2015 - $605 million), of which $63 million (2014 - $59 million) relates to mining equipment and is included in fuel and purchased power.

As a result of the Alberta OCA, we will cease coal-fired emissions by the end of 2030. The useful lives of the PP&E and amortizable intangibles associated with the coal assets were reduced to 2030. We also entered a Non-Utility Generator Enhanced Dispatch Contract for the Mississauga plant in December 2016. As a result, the useful life of the plant was shortened to the end of 2016.

Valuation of Goodwill

We evaluate goodwill for impairment at least annually, or more frequently if indicators of impairment exist. If the carrying amount of a CGU or group of CGUs, including goodwill, exceeds the unit's fair value, the excess represents a goodwill impairment loss. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets.

For purposes of the 2016 and 2015 annual goodwill impairment review, the Corporation determined the recoverable amounts of the test units by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

We reviewed the carrying amount of goodwill prior to year-end and determined that the fair values of the related CGUs or groups of CGUs to which goodwill relates, based on estimates of future cash flows, exceeded their carrying amounts, and no goodwill impairments existed.

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins, and fuel and operating costs. Had assumptions been made that resulted in fair values of the CGUs or groups of CGUs declining by five per cent from current levels, there would not have been any impairment of goodwill.

Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with TransAlta, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant to how we classify amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the value of certain items of revenue and expense is dependent upon such classifications.

Income Taxes

In accordance with IFRS, we use the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis.

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which we operate. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that our future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. The reduction of the deferred income tax asset can be reversed if the estimated future taxable income improves. No assurances can be given if any reversal will occur or the amount or timing of any such reversal. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than our estimates could materially impact the amount recognized for deferred income tax assets and liabilities. Our tax filings are subject to audit by taxation authorities. The outcome of some audits may change our tax liability, although we believe that we have adequately provided for income taxes in accordance with IFRS based on all information currently available. The outcome of pending audits is not known nor is the potential impact on the consolidated financial statements determinable.

Deferred income tax assets of $53 million (2015 - $71 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2016. These assets primarily relate to net operating loss carryforwards. We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist.

Deferred income tax liabilities of $712 million (2015 - $647 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2016. These liabilities are comprised primarily of taxes on unrealized gains from risk management transactions and income tax deductions in excess of related depreciation of PP&E.

Employee Future Benefits

We provide selected pension and post-employment benefits to employees. The cost of providing these benefits is dependent upon many factors that result from actual plan experience and assumptions of future experience.

The liabilities for future benefits and associated pension costs included in annual compensation expenses are impacted by employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets.

Changes to the provisions of the plans may also affect current and future pension costs. Pension costs may also be significantly impacted by changes in key actuarial assumptions, including, for example, the discount rates used in determining the defined benefit obligation and the net interest cost on the net defined benefit liability. The discount rate used to estimate our obligation reflects high-quality corporate fixed income securities currently available and expected to be available during the period to maturity of the pension benefits.

The plan assets are comprised primarily of equity and fixed income investments. Fluctuations in the return on plan assets as a result of actual equity market returns and changes in interest rates may result in increased or decreased pension costs in future periods.

Decommissioning and Restoration Provisions

We recognize decommissioning and restoration provisions for PP&E in the period in which they are incurred if there is a legal or constructive obligation to reclaim the plant or site. The amount recognized as a provision is the best estimate of the expenditures required to settle the provision. Expected values are probability weighted to deal with the risks and uncertainties inherent in the timing and amount of settlement of many decommissioning and restoration provisions. Expected values are discounted at the risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2016, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $293 million (2015 - $233 million). We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.1 billion, which will be incurred between 2017 and 2073. The majority of these costs will be incurred between 2020 and 2050. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	2
Undiscounted decommissioning and restoration provision	10	1

Other Provisions

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

Accounting Changes

A. Current Accounting Changes

I. Operating and Reportable Segments

During the first quarter, we disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Change in Estimates – Useful Lives

As a result of the Alberta OCA described above, we will cease coal-fired emissions by the end of 2030. The useful lives of the PP&E and amortizable intangibles associated with the Alberta coal assets were reduced to 2030 at the end of 2016. The useful lives may be revised or extended in compliance with our accounting policies, dependent upon future operating decisions and events.

We entered into a Non-Utility Generator Contract for the Mississauga plant in December 2016. As a result, the useful life of the plant was shortened to the end of 2016.

B. Future Accounting Changes

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

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licences of intellectual property, and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by us on Jan. 1, 2018.

We have created an implementation plan and are currently in the process of reviewing our various revenue streams and underlying contracts with customers to determine the impact that the adoption of IFRS 15 will have on our financial statements. Our implementation plan includes an assessment of the impacts on processes and controls which may be significant. Based on our initial scoping assessment, we have identified sources of revenue that are accounted for as leases or financial instruments that are excluded from the scope of IFRS 15. Thus, we are currently focusing efforts on evaluating the effect of IFRS 15 on revenue contracts such as our long-term electricity and thermal contracts, contracts for the sale of renewable attributes, merchant power revenue, and contracts for the sale of generation byproducts. Once we have developed the necessary accounting policies, estimates, judgments, and processes with respect to our revenue streams, the incremental compilation of historical data to make reasonable quantitative estimates of the effects of the new standard will commence. We have made progress on the implementation plan for IFRS 15 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 15 on our financial statements and disclosures.

Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid to late 2017.

II. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e., recognition of credit losses), and a new hedge accounting model. IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. IFRS 9 will be applied by us on Jan. 1, 2018.

Under the classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset. The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

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

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

We have created an implementation plan and are currently in the process of reviewing our various types of financial instruments to determine the potential impact. Our implementation plan includes an assessment of the impacts on processes and controls that may be significant. Based on our initial assessments, we anticipate financial statement impacts resulting from the implementation of the expected loss impairment model. The assessment of the financial statement impacts of implementing the classification and measure of financial assets and liabilities and hedge accounting model under IFRS 9 are ongoing. We made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on our financial statements and disclosures.

Our current estimate of the time and effort necessary to complete our implementation plan for IFRS 9 extends into mid to late 2017.

III. IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019, with early application permitted if IFRS 15 is also applied at the same time. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by us on Jan. 1, 2019.

We are in the process of completing our initial scoping assessment and expect to have an implementation plan in place by mid-2017. We anticipate most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2016	2015
Revenues	717	595
Comparable EBITDA(1)	374	268
Net earnings (loss) attributable to common shareholders	61	(7)
Comparable net earnings attributable to common shareholders(1)	51	3
Comparable FFO(1)	228	243
Cash flow from operating activities	122	118
Comparable FCF(1)	93	174
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.21	(0.02)
Comparable net earnings per share(1)	0.18	0.01
Comparable FFO per share(1)	0.79	0.86
Comparable FCF per share(1)	0.32	0.61
Dividends declared per common share	0.08	0.18

Financial Highlights

Comparable EBITDA for the fourth quarter of 2016 improved by $106 million compared to the same period in 2015, primarily as a result of the reversal of an $80 million provision relating to our Keephills 1 outage in 2013. Last year's comparable EBITDA was impacted by an increase to our provision of $59 million relating to prior years' Keephills 1 outage in 2013. Excluding the change to our provision, comparable EBITDA in the fourth quarter of 2016 was $33 million lower than the fourth quarter of 2015. Unrealized mark-to-market gains on our gas positions favourably affected our comparable EBITDA, but were offset by lower prices and lower availability in both our Canadian and U.S. Coal segments. Also impacting our results this quarter is lower margins from our Energy Marketing segment.

Comparable FFO decreased by $15 million to $228 million for the three months ended Dec. 31, 2016, compared to same period in 2015. The year-over-year non-cash change in our provisions totalled approximately $160 million and is excluded from comparable FFO. Comparable EBITDA also included $9 million of unrealized non-cash mark-to-market losses compared to a $6 million unrealized mark-to-market gain in 2015.

Fourth quarter comparable net earnings attributable to common shareholders was $51 million ($0.18 per share), up from the comparable net earnings of $3 million ($0.01 per share) in the same quarter last year. The Keephills 1 outage provision reversal as described above favourably impacted net earnings.

Reported net earnings attributable to common shareholders was $61 million ($0.21 per share) for the fourth quarter compared to a net loss of $7 million ($0.02 net loss per share) for the same period in 2015. The difference between comparable and reported net earnings includes the net gain on the Mississauga cogeneration facility recontracting, partially offsetting the Wintering Hills wind facility impairment charge during the quarter.

(1) These items are not defined under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Comparable Funds from Operations and Comparable Free Cash Flow and Earnings on a Comparable Basis 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	2016	2015
Availability (%)(1)	88.9	92.9
Adjusted availability (%)(2)	88.9	88.4
Production (GWh)(1)	10,624	11,107
Comparable EBITDA		
Canadian Coal	178	67
U.S. Coal(3)	14	22
Canadian Gas(3)	70	57
Australian Gas(3)	32	34
Wind and Solar	66	65
Hydro	20	19
Energy Marketing	13	26
Corporate	(19)	(22)
Total comparable EBITDA	374	268

Availability and Production

Adjusted availability for the three months ended Dec. 31, 2016, was consistent with the same period in 2015. Lower production for the three months ended Dec. 31, 2016, compared to the same period in 2015 are primarily due to higher outages and derates, partially offset by paid curtailments at our Canadian Coal segment, and higher economic dispatching in Ontario as a result of lower prices at our Canadian Gas segment.

- Canadian Coal: Comparable EBITDA totalled $178 million in the fourth quarter of 2016, including the reversal of the Keephills 1 outage provision of $80 million, partially offset by unrealized losses on hedging activities. The quarter-over-quarter change in our provisions was $139 million. Excluding the adjustment to our provision, comparable EBITDA was down $28 million compared to last year mainly due to lower realized prices and lower availability due to outages and derates.
- U.S. Coal: Comparable EBITDA was down $8 million in the fourth quarter compared to the same period in 2015. The unfavourable impact of mark-to-market losses on certain forward financial contracts that do not qualify for hedge accounting was partially offset by coal inventory recoveries. In addition, lower revenue and pricing was offset by lower delivered coal costs.
- Canadian Gas: Comparable EBITDA was $70 million in the fourth quarter of 2016, an increase of $13 million, compared to the same period in 2015, primarily due to favourable unrealized mark-to-market gains on our gas positon.
- Australian Gas: Comparable EBITDA was down by $2 million during the fourth quarter of 2016, compared to the same period in 2015. The addition of capacity payments for the gas conversion project at our Solomon gas plant was offset by increased repair and maintenance expenses and unfavourable Canadian dollar foreign exchange translation.
- Wind and Solar: Comparable EBITDA was consistent in the fourth quarter with the same period in 2015.
- Hydro: Comparable EBITDA was consistent in the fourth quarter with the same period in 2015.
- Energy Marketing: Comparable EBITDA was down $13 million in the fourth quarter compared to the same period in 2015 due to lower margins and increased OM&A costs associated with share-based payment expenses.
- Corporate: Lower costs in our Corporate Segment mainly due to realized benefits of cost efficiency initiatives which were offset by reduced allocations to our business segments.

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(1) Availability and production includes all generating assets under generation operations that we operate and finance leases and excludes hydro assets and equity investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.
(2) Adjusted for economic dispatching at U.S. Coal.
(3) See the Accounting Changes section of this MD&A for information on changes in the presentation of the Gas reportable segment.

Reconciliation of Non-IFRS Measures

We evaluate our performance and the performance of our business segments using a variety of measures. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company.

Comparable Funds from Operations and Comparable Free Cash Flow

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

	3 months ended Dec. 31	
	2016	2015
Cash flow from operating activities	122	118
Change in non-cash operating working capital balances	61	76
Cash flow from operations before changes in working capital	183	194
Adjustments		
Decrease in finance lease receivable	15	15
Restructuring costs	3	11
MSA settlement payment	25	31
Maintenance costs related to Alberta flood of 2013, net of insurance recoveries	-	(10)
Other	2	2
Comparable FFO	228	243
Deduct:		
Sustaining capital	(85)	(52)
Insurance recoveries of sustaining capital expenditures	-	23
Dividends paid on preferred shares	(10)	(11)
Distributions paid to subsidiaries' non-controlling interests	(40)	(29)
Comparable FCF	93	174
Weighted average number of common shares outstanding in the period	288	284
Comparable FFO per share	0.79	0.86
Comparable FCF per share	0.32	0.61

The table below provides a reconciliation of our comparable EBITDA to our comparable FFO and comparable FCF.

	3 months ended Dec. 31	
	2016	2015
Comparable EBITDA	374	268
Provisions	(79)	76
Interest expense	(47)	(63)
Unrealized (gains) losses from risk management activities	9	(6)
Current income tax expense	(6)	(7)
Decommissioning and restoration costs settled	(8)	(4)
Realized foreign exchange gain (loss)	(1)	1
Non-cash gain on curtailment and amendment gain on empoyee future benefits	-	(8)
Capital insurance recoveries	-	(5)
Other non-cash items	(14)	(9)
Comparable FFO	228	243
Deduct:		
Sustaining capital	(85)	(52)
Insurance recoveries of sustaining capital expenditures	-	23
Dividends paid on preferred shares	(10)	(11)
Distributions paid to subsidiaries' non-controlling interests	(40)	(29)
Comparable FCF	93	174
Weighted average number of common shares outstanding in the period	288	284
Comparable FFO per share	0.79	0.86
Comparable FCF per share	0.32	0.61

Reconciliation of Comparable EBITDA and Comparable Net Earnings

A reconciliation of reported results to comparable results for the three months ended Dec. 31, 2016 and 2015 is as follows:

	3 months ended Dec. 31, 2016				3 months ended Dec. 31, 2015			
	Reported	Comparable reclassifications	Comparable adjustments	Comparable total	Reported	Comparable reclassifications	Comparable adjustments	Comparable total
Revenues	717	32 (1, 2)	2 (4)	751	595	32 (1, 2)	13 (4)	640
Fuel and purchased power	280	(19) (3)	(14) (8)	247	272	(16) (3)	-	256
Gross margin	437	51	16	504	323	48	13	384
Operations, maintenance, and administration	125	-	-	125	109	-	10 (5)	119
Asset impairment reversals	28	-	(28)	-	(1)	-	1 (7)	-
Restructuring provision	-	-	- (7)	-	4	-	(4) (9)	-
Taxes, other than income taxes	7	-	-	7	8	-	-	8
Net other operating (income) losses	(193)	-	191 (8)	(2)	(29)	-	18 (6)	(11)
EBITDA	470	51	(147)	374	232	48	(12)	268
Depreciation and amortization	187	34 (2, 3)	(46) (8)	175	136	31 (2, 3)	-	167
Operating income	283	17	(101)	199	96	17	(12)	101
Finance lease income	17	(17) (1)	-	-	17	(17) (1)	-	-
Foreign exchange gain (loss)	(3)	-	(3) (11)	(6)	3	-	8 (11)	11
Gain on sale of assets	3	-	(4) (10)	(1)	(1)	-	1 (10)	-
Earnings before interest and taxes	300	-	(108)	192	115	-	(3)	112
Net interest expense	47	-	-	47	69	-	-	69
Income tax expense (recovery)	82	-	(40) (12, 13)	42	(4)	-	(6) (13)	(10)
Net earnings (loss)	171	-	(68)	103	50	-	3	53
Non-controlling interests	90	-	(58) (14)	32	46	-	(7) (14)	39
Net earnings (loss) attributable to TransAlta shareholders	81	-	(10)	71	4	-	10	14
Preferred share dividends	20	-	-	20	11	-	-	11
Net earnings (loss) attributable to common shareholders	61	-	(10)	51	(7)	-	10	3
Weighted average number of common shares outstanding in the period	288			288	284			284
Net earnings (loss) per share attributable to common shareholders	0.21			0.18	(0.02)			0.01

The adjustments made to calculate comparable earnings for the three months ended Dec. 31, 2016 and 2015 are as follows. References are to the previous reconciliation table.

				3 months ended Dec. 31	
				2016	2015
Reference number	**Adjustment**	**Segment**	**Financial statement line item**		
Reclassifications:					
1	Finance lease income used as a proxy for operating revenue	Australian Gas	Revenues	**13**	13
		Canadian Gas	Revenues	**4**	4
2	Decrease in finance lease receivable used as a proxy for operating revenue and depreciation	Canadian Gas	Revenues	**14**	15
		Australian Gas	Revenues	**1**	-
3	Reclassification of mine depreciation from fuel and purchased power	Canadian Coal	Fuel and purchased power	**19**	16
Adjustments (increasing (decreasing) earnings to arrive at comparable results):					
4	Impacts to revenue associated with certain de-designated and economic hedges	U.S. Coal	Revenues	**2**	13
5	Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	Hydro	OM&A	**-**	(10)
6	Non-comparable portion of insurance recovery received	Hydro	Net other operating (income) losses	**-**	(18)
7	Asset impairment reversals	U.S. Coal	Asset impairment (reversals)	**-**	(1)
		Wind and Solar	Asset impairment (reversals)	**28**	-
8	Mississauga recontracting(1)	Canadian Gas	Net other operating (income) losses	**(131)**	-
9	Restructuring expense	Canadian Coal	Restructuring provision	**-**	2
		Corporate	Restructuring provision	**-**	2
10	Gain on Poplar Creek contract restructuring	Canadian Gas	Gain on sale of assets	**-**	1
	Non-comparable gain on sale of assets	Corporate	Gain on sale of assets	**(4)**	-
11	Economic hedges of non-controlling interest in intercompany foreign exchange contracts	Unassigned	Foreign exchange loss	**(3)**	8
12	Net tax effect on comparable adjustments subject to tax	Unassigned	Income tax expense (recovery)	**9**	-
13	Reversal of a writedown of deferred income tax assets	Unassigned	Income tax expense (recovery)	**31**	6
14	Non-comparable items attributable to non-controlling interests	Unassigned	Non-controlling interests	**58**	7

(1) Reported in net other operating (income) loss of ($191 million), depreciation and amortization of ($46 million) and fuel and purchased power of ($14 million).

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are usually incurred in the spring and fall when electricity prices are expected to be lower, as electricity prices generally increase in the peak winter and summer months in our main markets due to increased heating and cooling loads. Margins are also typically impacted in the second quarter due to the volume of hydro production resulting from spring runoff and rainfall in the Pacific Northwest, which impacts production at U.S. Coal. Typically, hydro facilities generate most of their electricity and revenues during the spring months when melting snow starts feeding watersheds and rivers. Inversely, wind speeds are historically greater during the cold winter months and lower in the warm summer months.

	Q1 2016	Q2 2016	Q3 2016	**Q4 2016**
Revenues	568	492	620	**717**
Comparable EBITDA	279	248	244	**374**
Comparable FFO	196	175	163	**228**
Net earnings (loss) attributable to common shareholders	62	6	(12)	**61**
Comparable net earnings (loss) attributable to common shareholders	14	(20)	(11)	**51**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	0.22	0.02	(0.04)	**0.21**
Comparable net earnings (loss) per share, basic and diluted[1]	0.05	(0.07)	(0.04)	**0.18**

	Q1 2015	Q2 2015	Q3 2015	Q4 2015
Revenues	593	438	641	595
Comparable EBITDA	275	183	219	268
Comparable FFO	211	160	126	243
Net earnings (loss) attributable to common shareholders	(40)	(131)	154	(7)
Comparable net earnings (loss) attributable to common shareholders	26	(44)	(33)	3
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	(0.14)	(0.47)	0.55	(0.02)
Comparable net earnings (loss) per share, basic and diluted[1]	0.09	(0.16)	(0.12)	0.01

(1) Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average common shares outstanding during the period. As a result, the sum of the earnings per share for the four quarters making up the calendar year may sometimes differ from the annual earnings per share.

Comparable net earnings, comparable EBITDA, and comparable FFO are generally higher in the first and fourth quarters due to higher demand associated with winter cold in the markets in which we operate and lower planned outages.

Net earnings attributable to common shareholders has also been impacted by the following variations and events:

- gain on disposal of assets, following the Poplar Creek contract restructuring in the third quarter of 2015,
- U.S. Solar and Wind acquisitions in the third quarter of 2015,
- settlement with the Market Surveillance Administrator in the third quarter of 2015,
- a recovery of a writedown of deferred tax assets in the fourth quarter of 2014, the third quarter of 2015, and the first and second quarters of 2016,
- change in income tax rates in Alberta in the second quarter of 2015,
- deferred income tax impacts of the sale of an economic interest in Australian Assets to TransAlta Renewables in the first and second quarters of 2015,
- effects of non-comparable unrealized losses on intercompany financial instruments that are attributable only to the non-controlling interests in the first, second, and third quarters of 2016,
- effects of the Mississauga facility recontracting during the fourth quarter of 2016, and
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016.

Disclosure Controls and Procedures

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Disclosure controls and procedures refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under the Securities Exchange Act of 1934, as amended ("Exchange Act") are recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in our reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding our required disclosure. In designing and evaluating our disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and management is required to apply its judgment in evaluating and implementing possible controls and procedures.

During the first quarter of 2016, we completed the implementation of a new energy trading and risk management system. In connection with the implementation, we updated the processes that constitute our internal control over financial reporting, as necessary, to accommodate related changes to our business processes and accounting procedures.

Except as otherwise described above, there have been no other changes in our internal control over financial reporting during the year ended Dec. 31, 2016 that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2016, the end of the period covered by this report, our disclosure controls and procedures were effective.

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

The consolidated financial statements and other financial information included in this annual report have been prepared by management. It is management's responsibility to ensure that sound judgment, appropriate accounting principles and methods, and reasonable estimates have been used to prepare this information. They also ensure that all information presented is consistent.

Management is also responsible for establishing and maintaining internal controls and procedures over the financial reporting process. The internal control system includes an internal audit function and an established business conduct policy that applies to all employees. In addition, TransAlta Corporation has a code of conduct that applies to all employees and is signed annually. The code of conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures, and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

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

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

March 2, 2017

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 2013 framework to evaluate the effectiveness of TransAlta's internal control over financial reporting. Management believes that the COSO 2013 framework is a suitable framework for its evaluation of TransAlta's internal control over financial reporting because it is free from bias, permits reasonably consistent qualitative and quantitative measurements of TransAlta's internal controls, is sufficiently complete so that those relevant factors that would alter a conclusion about the effectiveness of TransAlta's internal controls are not omitted, and is relevant to an evaluation of internal control over financial reporting.

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

TransAlta proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards ("IFRS"). Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2016 consolidated financial statements of TransAlta included $626 million and $592 million of total and net assets, respectively, as of December 31, 2016, and $138 million and $13 million of revenues and net loss, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at December 31, 2016, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended December 31, 2016, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

March 2, 2017

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), (the COSO criteria). TransAlta Corporation's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit.

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

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2016 consolidated financial statements of the Corporation and constituted $626 million and $592 million of total and net assets, respectively, as of December 31, 2016, and $138 million and $13 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of the Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statements of financial position as at December 31, 2016 and 2015, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the three-year period ended December 31, 2016 of TransAlta Corporation and our report dated March 2, 2017 expressed an unqualified opinion thereon.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 2, 2017

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

We have audited the accompanying consolidated financial statements of TransAlta Corporation, which comprise the consolidated statements of financial position as at December 31, 2016 and 2015, and the consolidated statements of earnings (loss), comprehensive income (loss), changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation as at December 31, 2016 and 2015, and its financial performance and its cash flows for each of the years in the three-year period ended December 31, 2016, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransAlta Corporation's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 2, 2017 expressed an unqualified opinion on TransAlta Corporation's internal control over financial reporting.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 2, 2017

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	2016	2015	2014
Revenues *(Note 33)*	2,397	2,267	2,623
Fuel and purchased power *(Note 5)*	963	1,008	1,092
Gross margin	1,434	1,259	1,531
Operations, maintenance, and administration *(Note 5)*	489	492	542
Depreciation and amortization	601	545	538
Asset impairment charges (reversals) *(Note 6)*	28	(2)	(6)
Restructuring provision *(Note 4)*	1	22	-
Taxes, other than income taxes	31	29	29
Net other operating (income) losses *(Note 8)*	(194)	25	(14)
Operating income	478	148	442
Finance lease income *(Note 7)*	66	58	49
Net interest expense *(Note 9)*	(229)	(251)	(254)
Foreign exchange gain (loss)	(5)	4	-
Gain on sale of assets *(Note 4)*	4	262	2
Earnings before income taxes	314	221	239
Income tax expense *(Note 10)*	38	105	7
Net earnings	276	116	232

Net earnings attributable to:			
TransAlta shareholders	169	22	182
Non-controlling interests *(Note 11)*	107	94	50
	276	116	232

Net earnings attributable to TransAlta shareholders	169	22	182
Preferred share dividends *(Note 24)*	52	46	41
Net earnings (loss) attributable to common shareholders	117	(24)	141
Weighted average number of common shares outstanding in the year *(millions)*	288	280	273

Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 23)*	0.41	(0.09)	0.52

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	2016	2015	2014
Net earnings	276	116	232
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	8	4	(20)
Gains (losses) on derivatives designated as cash flow hedges, net of tax[2]	(1)	3	(1)
Total items that will not be reclassified subsequently to net earnings	7	7	(21)
Gains (losses) on translating net assets of foreign operations, net of tax[3]	(71)	247	75
Reclassification of translation gains on net assets of divested foreign operations *(Note 4)*	-	(10)	(7)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[4]	18	(172)	(58)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[5] *(Note 4)*	-	6	7
Gains on derivatives designated as cash flow hedges, net of tax[6]	179	375	215
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[7]	(48)	(194)	(45)
Total items that will be reclassified subsequently to net earnings	78	252	187
Other comprehensive income	85	259	166
Total comprehensive income	361	375	398

Total comprehensive income attributable to:			
TransAlta shareholders	215	272	348
Non-controlling interests *(Note 11)*	146	103	50
	361	375	398

(1) Net of income tax expense of 4 for the year ended Dec. 31, 2016 (2015 - nil, 2014 - 7 recovery).

(2) Net of income tax expense of nil the year ended Dec. 31, 2016 (2015 - 1 expense, 2014 - nil).

(3) Net of income tax expense of 11 for the year ended Dec. 31, 2016 (2015 - nil, 2014 - nil).

(4) Net of income tax expense of 5 for the year ended Dec. 31, 2016 (2015 - 7 expense, 2014 - 7 recovery).

(5) Net of reclassification of income tax recovery of nil for the year ended Dec. 31, 2016 (2015 - 1 recovery, 2014 - 1 recovery).

(6) Net of income tax expense of 92 for the year ended Dec. 31, 2016 (2015 - 138 expense, 2014 - 91 expense).

(7) Net of reclassification of income tax expense of 41 for the year ended Dec. 31, 2016 (2015 - 50 expense, 2014 - 3 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	2016	2015
Cash and cash equivalents	305	54
Trade and other receivables *(Note 12)*	703	567
Prepaid expenses	23	26
Risk management assets *(Notes 13 and 14)*	249	298
Inventory *(Note 15)*	213	219
Assets held for sale *(Note 4)*	61	-
	1,554	1,164
Long-term portion of finance lease receivables	719	775
Property, plant, and equipment *(Note 16)*		
Cost	12,773	12,854
Accumulated depreciation	(5,949)	(5,681)
	6,824	7,173
Goodwill (Note 17)	464	465
Intangible assets (Note 18)	355	369
Deferred income tax assets *(Note 10)*	53	71
Risk management assets *(Notes 13 and 14)*	785	797
Other assets *(Note 19)*	242	133
Total assets	10,996	10,947
Accounts payable and accrued liabilities	413	334
Current portion of decommissioning and other provisions *(Note 20)*	39	166
Risk management liabilities *(Notes 13 and 14)*	66	200
Income taxes payable	6	3
Dividends payable *(Note 23)*	54	63
Current portion of long-term debt and finance lease obligations *(Note 21)*	639	87
	1,217	853
Credit facilities, long-term debt, and finance lease obligations *(Note 21)*	3,722	4,408
Decommissioning and other provisions *(Note 20)*	304	232
Deferred income tax liabilities *(Note 10)*	712	647
Risk management liabilities *(Notes 13 and 14)*	48	69
Defined benefit obligation and other long-term liabilities (Note 22)	330	348
Equity		
Common shares *(Note 23)*	3,094	3,075
Preferred shares *(Note 24)*	942	942
Contributed surplus	9	9
Deficit	(933)	(1,018)
Accumulated other comprehensive income *(Note 25)*	399	353
Equity attributable to shareholders	3,511	3,361
Non-controlling interests *(Note 11)*	1,152	1,029
Total equity	4,663	4,390
Total liabilities and equity	10,996	10,947

Commitments and contingencies *(Note 32)*

Subsequent events *(Note 34)*

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[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2014	2,999	942	9	(770)	104	3,284	594	3,878
Net earnings	-	-	-	22	-	22	94	116
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	71	71	-	71
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	177	177	7	184
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	4	4	-	4
Intercompany available-for-sale investments	-	-	-	-	(2)	(2)	2	-
Total comprehensive income				22	250	272	103	375
Common share dividends	-	-	-	(203)	-	(203)	-	(203)
Preferred share dividends	-	-	-	(46)	-	(46)	-	(46)
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	-	-	-	(21)	(1)	(22)	437	415
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(105)	(105)
Common shares issued	76	-	-	-	-	76	-	76
Balance, Dec. 31, 2015	3,075	942	9	(1,018)	353	3,361	1,029	4,390
Net earnings	-	-	-	169	-	169	107	276
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	-	-	-	-	(53)	(53)	-	(53)
Net gains on derivatives designated as cash flow hedges, net of tax	-	-	-	-	106	106	24	130
Net actuarial gains on defined benefits plans, net of tax	-	-	-	-	8	8	-	8
Intercompany available-for-sale investments	-	-	-	-	(15)	(15)	15	-
Total comprehensive income				169	46	215	146	361
Common share dividends	-	-	-	(58)	-	(58)	-	(58)
Preferred share dividends	-	-	-	(52)	-	(52)	-	(52)
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	-	-	-	26	-	26	138	164
Distributions paid, and payable, to non-controlling interests	-	-	-	-	-	-	(161)	(161)
Common shares issued	19	-	-	-	-	19	-	19
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663

(1) Refer to Note 25 for details on components of, and changes in, accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2016**	2015	2014
Operating activities			
Net earnings	**276**	116	232
Depreciation and amortization *(Note 33)*	**664**	605	595
Gain on sale of assets *(Note 4)*	**(1)**	(262)	(2)
California claim *(Note 8)*	**-**	-	(28)
Accretion of provisions *(Note 20)*	**20**	21	18
Decommissioning and restoration costs settled *(Note 20)*	**(23)**	(24)	(16)
Deferred income tax expense (recovery) *(Note 10)*	**15**	86	(26)
Unrealized (gain) loss from risk management activities	**58**	61	(50)
Unrealized foreign exchange (gain) loss	**(1)**	13	11
Provisions	**(123)**	101	-
Asset impairment charges (reversals) *(Note 6)*	**28**	(2)	(6)
Other non-cash items	**(242)**	(41)	(5)
Cash flow from operations before changes in working capital	**671**	674	723
Change in non-cash operating working capital balances *(Note 29)*	**73**	(242)	73
Cash flow from operating activities	**744**	432	796
Investing activities			
Additions to property, plant, and equipment *(Notes 16 and 33)*	**(358)**	(476)	(487)
Additions to intangibles *(Notes 18 and 33)*	**(21)**	(26)	(34)
Acquisition of renewable energy facilities, net of cash acquired *(Note 4)*	**-**	(101)	-
Addition to assets held for sale	**-**	-	(13)
Proceeds on sale of property, plant, and equipment	**6**	7	6
Proceeds on sale of investments and development projects *(Note 4)*	**-**	-	224
Realized losses on financial instruments	**(6)**	(12)	(2)
Decrease in finance lease receivable	**56**	23	3
Other	**2**	24	9
Change in non-cash investing working capital balances	**(6)**	(12)	2
Cash flow used in investing activities	**(327)**	(573)	(292)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 21)*	**(315)**	218	(436)
Repayment of long-term debt *(Note 21)*	**(88)**	(758)	(551)
Issuance of long-term debt *(Note 21)*	**361**	487	434
Dividends paid on common shares *(Note 23)*	**(69)**	(124)	(140)
Dividends paid on preferred shares *(Note 24)*	**(42)**	(46)	(41)
Net proceeds on issuance of preferred shares *(Note 24)*	**-**	-	161
Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)*	**162**	404	129
Realized gains (losses) on financial instruments	**(2)**	87	35
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(151)**	(99)	(84)
Decrease in finance lease obligations *(Note 21)*	**(16)**	(13)	(10)
Other	**(3)**	(7)	-
Cash flow from (used in) financing activities	**(163)**	149	(503)
Cash flow from operating, investing, and financing activities	**254**	8	1
Effect of translation on foreign currency cash	**(3)**	3	-
Increase in cash and cash equivalents	**251**	11	1
Cash and cash equivalents, beginning of year	**54**	43	42
Cash and cash equivalents, end of year	**305**	54	43
Cash income taxes paid	**27**	17	31
Cash interest paid	**235**	242	230

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

TransAlta Corporation ("TransAlta" or the "Corporation") was incorporated under the *Canada Business Corporations Act* in March 1985. The Corporation became a public company in December 1992. Its head office is located in Calgary, Alberta.

I. Generation Segments

The six generation segments of the Corporation are as follows: Canadian Coal, U.S. Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro. The Corporation owns and operates hydro, wind and solar, natural-gas- and coal-fired facilities, and related mining operations in Canada, the United States ("U.S."), and Australia. Revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Canadian Coal segment.

II. Energy Marketing Segment

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

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

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

III. Corporate

The Corporate segment includes the Corporation's central financial, legal, administrative, and investor relation functions. Charges directly or reasonably attributable to other segments are allocated thereto.

B. Basis of Preparation

These consolidated financial statements have been prepared by management in compliance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements have been prepared on a historical cost basis except for financial instruments and assets held for sale, which are measured at fair value, as explained in the following accounting policies.

These consolidated financial statements were authorized for issue by the Board on March 2, 2017.

C. Basis of Consolidation

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

2. Significant Accounting Policies

A. Revenue Recognition

The majority of the Corporation's revenues are derived from the sale of physical power, leasing of power facilities, and from energy marketing and trading activities.

Revenues are measured at the fair value of the consideration received or receivable.

Revenues under long-term electricity and thermal sales contracts generally include one or more of the following components: fixed capacity payments for availability, energy payments for generation of electricity, incentives or penalties for exceeding or not meeting availability targets, excess energy payments for power generation above committed capacity, and ancillary services. Each component is recognized when: i) output, delivery, or satisfaction of specific targets is achieved, all as governed by contractual terms; ii) the amount of revenue can be measured reliably; iii) it is probable that the economic benefits will flow to the Corporation; and iv) the costs incurred or to be incurred in respect of the transaction can be measured reliably. Revenue from the rendering of services is recognized when criteria ii), iii), and iv) above are met and when the stage of completion of the transaction at the end of the reporting period can be measured reliably.

Revenues from non-contracted capacity are comprised of energy payments, at market prices, for each megawatt hour ("MWh") produced, and are recognized upon delivery.

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Revenues associated with leases are recognized as outlined in Note 2(R).

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts, and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Foreign Currency Translation

The Corporation, its subsidiary companies, and joint arrangements each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar, while the functional currencies of its subsidiary companies and joint arrangements are the Canadian, US, or Australian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

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

C. Financial Instruments and Hedges

I. Financial Instruments

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

Financial assets and financial liabilities classified or designated as at fair value through profit or loss are measured at fair value with changes in fair values recognized in net earnings. Financial assets classified as either held-to-maturity or as loans and receivables, and other financial liabilities, are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial assets are those non-derivative financial assets that are designated as such or that have not been classified as another type of financial asset, and are measured at fair value through OCI. Available-for-sale financial assets are measured at cost if fair value is not reliably measurable.

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

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

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

Derivative instruments that are embedded in financial or non-financial contracts that are not already required to be recognized at fair value are treated and recognized as separate derivatives if their risks and characteristics are not closely related to their host contracts and the contract is not measured at fair value. Changes in the fair values of these and other derivative instruments are recognized in net earnings with the exception of the effective portion of i) derivatives designated as cash flow hedges and ii) hedges of foreign currency exposure of a net investment in a foreign operation, each of which is recognized in OCI. Derivatives used in commodity risk management activities are described in more detail in Note 2(A).

Transaction costs are expensed as incurred for financial instruments classified or designated as at fair value through profit or loss. For other financial instruments, such as debt instruments, transaction costs are recognized as part of the carrying amount of the financial instrument. The Corporation uses the effective interest method of amortization for any transaction costs or fees, premiums, or discounts earned or incurred for financial instruments measured at amortized cost.

II. Hedges

Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge, or a hedge of foreign currency exposures of a net investment in a foreign operation. A hedging relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedge is expected to be highly effective at inception and on an ongoing basis. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

The Corporation formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives used are highly effective in offsetting changes in fair values or cash flows of hedged items. If hedge criteria are not met or the Corporation does not apply hedge accounting, the derivative is accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

a. Fair Value Hedges

In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings. Hedge effectiveness for fair value hedges is achieved if changes in the fair value of the derivative are highly effective at offsetting changes in the fair value of the item hedged. If hedge accounting is discontinued, the carrying amount of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying amount of the hedged item are amortized to net earnings over the remaining term of the original hedging relationship.

The Corporation primarily uses interest rate swaps as fair value hedges to manage the ratio of floating rate versus fixed rate debt. Interest rate swaps require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps.

b. Cash Flow Hedges

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. Hedge effectiveness is achieved if the derivative's cash flows are highly effective at offsetting the cash flows of the hedged item and the timing of the cash flows is similar. All components of each derivative's change in fair value are included in the assessment of cash flow hedge effectiveness. If hedge accounting is discontinued, the amounts previously recognized in AOCI are reclassified to net earnings during the periods when the variability in the cash flows of the hedged item affects net earnings. Gains and losses on derivatives are reclassified to net earnings from AOCI immediately when the forecasted transaction is no longer expected to occur within the time period specified in the hedge documentation.

The Corporation primarily uses physical and financial swaps, forward sales contracts, futures contracts, and options as cash flow hedges to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. If hedging criteria are met, the fair values of the hedges are recorded in risk management assets or liabilities with changes in value being reported in OCI. Gains and losses on these derivatives are recognized, on settlement, in net earnings in the same period and financial statement caption as the hedged exposure.

The Corporation also uses foreign currency forward contracts as cash flow hedges to hedge the foreign exchange exposures resulting from highly probable forecasted project-related transactions denominated in foreign currencies. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. Upon settlement of the derivative, any gain or loss on the forward contracts is included in the cost of the asset acquired or liability incurred.

The Corporation uses forward starting interest rate swaps as cash flow hedges to hedge exposures to anticipated changes in interest rates for forecasted issuances of debt. If the hedging criteria are met, changes in fair value are reported in OCI with the fair value being reported in risk management assets or liabilities, as appropriate. When the swaps are closed out on issuance of the debt, the resulting gains or losses recorded in AOCI are amortized to net earnings over the term of the swap. If no debt is issued, the gains or losses are recognized in net earnings immediately.

c. Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal, or loss of control. The Corporation primarily uses foreign currency forward contracts and foreign-denominated debt to hedge exposure to changes in the carrying values of the Corporation's net investments in foreign operations that result from changes in foreign exchange rates.

D. Cash and Cash Equivalents

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

E. Collateral Paid and Received

The terms and conditions of certain contracts may require the Corporation or its counterparties to provide collateral when the fair value of the obligation pursuant to these contracts is in excess of any credit limits granted. Downgrades in creditworthiness by certain credit rating agencies may decrease the credit limits granted and accordingly increase the amount of collateral that may have to be provided.

F. Inventory

I. Fuel

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

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

II. Energy Marketing

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

III. Parts and Materials

Parts, materials, and supplies are recorded at the lower of cost, measured at moving average costs, and net realizable value.

G. Property, Plant, and Equipment

The Corporation's investment in property, plant, and equipment ("PP&E") is initially measured at the original cost of each component at the time of construction, purchase, or acquisition. A component is a tangible portion of an asset that can be separately identified and depreciated over its own expected useful life, and is expected to provide a benefit for a period in excess of one year. Original cost includes items such as materials, labour, borrowing costs, and other directly attributable costs, including the initial estimate of the cost of decommissioning and restoration. Costs are recognized as PP&E assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

Planned maintenance is performed at regular intervals. Planned major maintenance includes inspection, repair, and maintenance of existing components, and the replacement of existing components. Costs incurred for planned major maintenance activities are capitalized in the period maintenance activities occur and are amortized on a straight-line basis over the term until the next major maintenance event. Expenditures incurred for the replacement of components during major maintenance are capitalized and amortized over the estimated useful life of such components.

The cost of routine repairs and maintenance and the replacement of minor parts are charged to net earnings as incurred.

Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

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

The estimate of the useful lives of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values, and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value, or depreciation method is accounted for prospectively.

Estimated useful lives of the components of depreciable assets, categorized by asset class, are as follows:

Coal generation	3-50 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	4-50 years
Capital spares and other	2-50 years

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

H. Intangible Assets

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

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

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

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

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

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

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

Factors that could indicate that an impairment exists include: significant underperformance relative to historical or projected operating results; significant changes in the manner in which an asset is used, or in the Corporation's overall business strategy; or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occurs over a period of time leading to an indication that an asset may be impaired. This can be further complicated in situations where the Corporation is not the operator of the facility. Events can occur in these situations that may not be known until a date subsequent to their occurrence.

The Corporation's operations, the market, and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss is recognized in net earnings, and the asset's carrying amount is reduced to its recoverable amount.

At each reporting date, an assessment is made whether there is any indication that an impairment loss previously recognized may no longer exist or may have decreased. If such indication exists, the recoverable amount of the asset or CGU to which the asset belongs is estimated and the impairment loss previously recognized is reversed if there has been an increase in the recoverable amount. Where an impairment loss is subsequently reversed, the carrying amount of the asset is increased to the lesser of the revised estimate of its recoverable amount or the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized previously. A reversal of an impairment loss is recognized in net earnings.

J. Goodwill

Goodwill arising in a business combination is recognized as an asset at the date control is acquired. Goodwill is measured as the cost of an acquisition plus the amount of any non-controlling interest in the acquiree (if applicable) less the fair value of the related identifiable assets acquired and liabilities assumed.

Goodwill is not subject to amortization, but is tested for impairment at least annually, or more frequently, if an analysis of events and circumstances indicate that a possible impairment may exist. These events could include a significant change in financial position of the CGUs or groups of CGUs to which the goodwill relates or significant negative industry or economic trends. For impairment purposes, goodwill is allocated to each of the Corporation's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. To test for impairment, the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount. If the recoverable amount is less than the carrying amount, an impairment loss is recognized in net earnings immediately, by first reducing the carrying amount of the goodwill, and then by reducing the carrying amount of the other assets in the unit. An impairment loss recognized for goodwill is not reversed in subsequent periods.

K. Project Development Costs

Project development costs include external, direct, and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized as operating expenses until construction of a plant or acquisition of an investment is likely to occur, there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, at which time the costs incurred subsequently are included in other assets. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

The Corporation uses the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are recognized on the differences between the carrying amounts of assets and liabilities and their respective income tax basis (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied. Deferred income tax assets and liabilities are measured based on income tax rates and tax laws that are enacted or substantively enacted by the end of the reporting period and that are expected to apply in the years in which temporary differences are expected to be realized or settled. Deferred income tax is charged or credited to net earnings, except when related to items charged or credited to either OCI or directly to equity. The carrying amount of deferred income tax assets is evaluated at the end of each reporting period and is reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be realized.

Deferred income tax liabilities are recognized for taxable temporary differences arising on investments in subsidiaries, except where the Corporation is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

M. Employee Future Benefits

The Corporation has defined benefit pension and other post-employment benefit plans. The current service cost of providing benefits under the defined benefit plans is determined using the projected unit credit method pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

Gains or losses arising from either a curtailment or settlement of a defined benefit plan are recognized when the curtailment or settlement occurs. When the restructuring of a benefit plan gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to the settlement.

In determining whether statutory minimum funding requirements of the Corporation's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Corporation as security are considered to alleviate the funding requirements. No additional liability results in these circumstances.

Contributions payable under defined contribution pension plans are recognized as a liability and an expense in the period in which the services are rendered.

N. Provisions

Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby through an established pattern of past practice, published policies, or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, remeasured at each period-end, of the expenditures required to settle the present obligation, considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk-adjusted interest rate.

The Corporation records a decommissioning and restoration provision for all generating facilities and mine sites for which it is legally or constructively required to remove the facilities at the end of their useful lives and restore the plant or mine sites. For some hydro facilities, the Corporation is required to remove the generating equipment, but is not required to remove the structures. Initial decommissioning provisions are recognized at their present value when incurred. Each reporting date, the Corporation determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Corporation recognizes the initial decommissioning and restoration provisions, as well as changes resulting from revisions to cost estimates and period-end revisions to the market-based, risk-adjusted discount rate, as a cost of the related PP&E (see Note 2(G)). The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense. Where the Corporation expects to receive reimbursement from a third party for a portion of future decommissioning costs, the reimbursement is recognized as a separate asset when it is virtually certain that the reimbursement will be received. Decommissioning and restoration obligations for coal mines are incurred over time, as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

Changes in other provisions resulting from revisions to estimates of expenditures required to settle the obligation or period-end revisions to the market-based, risk-adjusted discount rate are recognized in net earnings. The accretion of the net present value discount is charged to net earnings each period and is included in net interest expense.

O. Share-Based Payments

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

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

P. Emission Credits and Allowances

Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

Emission credits and allowances that are held for trading and that meet the definition of a derivative are accounted for using the fair value method of accounting. Emission credits and allowances that do not satisfy the criteria of a derivative are accounted for using the accrual method.

Q. Assets Held for Sale

Assets are classified as held for sale if their carrying amount will be recovered primarily through a sale as opposed to continued use by the Corporation. Assets classified as held for sale are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment is recognized in net earnings. Depreciation and equity accounting ceases when an asset or equity investment, respectively, is classified as held for sale. Assets classified as held for sale are reported as current assets in the Consolidated Statements of Financial Position.

R. Leases

A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

Power purchase arrangements ("PPA") and other long-term contracts may contain, or may be considered, leases where the fulfillment of the arrangement is dependent on the use of a specific asset (e.g. a generating unit) and the arrangement conveys to the customer the right to use that asset.

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

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life. Rental income, including contingent rent, from operating leases is recognized over the term of the arrangement and is reflected in revenue on the Consolidated Statements of Earnings (Loss). Contingent rent may arise when payments due under the contract are not fixed in amount but vary based on a future factor such as the amount of use or production.

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

S. Borrowing Costs

TransAlta capitalizes borrowing costs that are directly attributable to, or relate to general borrowings used for, the construction of qualifying assets. Qualifying assets are assets that take a substantial period of time to prepare for their intended use and typically include generating facilities or other assets that are constructed over periods of time exceeding 12 months. Borrowing costs are considered to be directly attributable if they could have been avoided if the expenditure on the qualifying asset had not been made. Borrowing costs that are capitalized are included in the cost of the related PP&E component. Capitalization of borrowing costs ceases when substantially all the activities necessary to prepare the asset for its intended use are complete.

All other borrowing costs are expensed in the period in which they are incurred.

T. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Corporation acquires less than a 100 per cent interest. Non-controlling interests are initially measured at either fair value or at the non-controlling interest's proportionate share of the acquiree's identifiable net assets. The Corporation determines on a transaction by transaction basis which measurement method is used. Non-controlling interests also arise from other contractual arrangements between the Corporation and other parties, whereby the other party has acquired an interest in a specified asset or operation, and the Corporation retains control.

Subsequent to acquisition, the carrying amount of non-controlling interests is increased or decreased by the non-controlling interest's share of subsequent changes in equity and payments to the non-controlling interest. Total comprehensive income is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

U. Joint Arrangements

A joint arrangement is a contractual arrangement that establishes the terms by which two or more parties agree to undertake and jointly control an economic activity. TransAlta's joint arrangements are generally classified as two types: joint operations and joint ventures.

A joint operation arises when the parties that have joint control have rights to the assets and obligations for the liabilities relating to the arrangement. Generally, each party takes a share of the output from the asset and each bears an agreed upon share of the costs incurred in respect of the joint operation. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues, and expenses in respect of its interest in the joint operation.

In a joint venture, the venturers do not have rights to individual assets or obligations of the venture. Rather, each venturer has rights to the net assets of the arrangement. The Corporation reports its interests in joint ventures using the equity method. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation's share of the joint venture's net earnings or loss after the date of acquisition. The impact of transactions between the Corporation and joint ventures is eliminated based on the Corporation's ownership interest. Distributions received from joint ventures reduce the carrying amount of the investment. Any excess of the cost of an acquisition less the fair value of the recognized identifiable assets, liabilities, and contingent liabilities of an acquired joint venture is recognized as goodwill and is included in the carrying amount of the investment and is assessed for impairment as part of the investment.

Investments in joint ventures are evaluated for impairment at each reporting date by first assessing whether there is objective evidence that the investment is impaired. If such objective evidence is present, an impairment loss is recognized if the investment's recoverable amount is less than its carrying amount. The investment's recoverable amount is determined as the higher of value in use and fair value less costs of disposal.

V. Government Incentives

Government incentives are recognized when the Corporation has reasonable assurance that it will comply with the conditions associated with the incentive and that the incentive will be received. When the incentive relates to an expense item, it is recognized in net earnings over the same period in which the related costs or revenues are recognized. When the incentive relates to an asset, it is recognized as a reduction of the carrying amount of PP&E and released to earnings as a reduction in depreciation over the expected useful life of the related asset.

W. Earnings per Share

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

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

X. Business Combinations

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

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

Y. Stripping Costs

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

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

In the process of applying the Corporation's accounting policies, management has to make judgments and estimates about matters that are highly uncertain at the time the estimate is made and that could significantly affect the amounts recognized in the consolidated financial statements. Different estimates with respect to key variables used in the calculations, or changes to estimates, could potentially have a material impact on the Corporation's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment loss may exist or that a previously recognized impairment loss may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset. In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs, and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations, and transmission capacity or constraints for the remaining life of the facilities. Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity, and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU, or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material. The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs, or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Corporation evaluates the market design, transmission constraints, and the contractual profile of each facility, as well as the Corporation's own commodity price risk management plans and practices, in order to inform this determination. With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization, future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2014 to 2016 is found in Notes 6 and 17.

II. Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfillment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations, and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. See Note 10 for further details on the impacts of the Corporation's tax policies.

IV. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 13. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

The determination of the fair value of these contracts and derivative instruments can be complex and relies on judgments and estimates concerning future prices, volatility, and liquidity, among other factors. These fair value estimates may not necessarily be indicative of the amounts that could be realized or settled, and changes in these assumptions could affect the reported fair value of financial instruments. Fair values can fluctuate significantly and can be favourable or unfavourable depending on current market conditions. Judgment is also used in determining whether a highly probable forecasted transaction designated in a cash flow hedge is expected to occur based on the Corporation's estimates of pricing and production to allow the future transaction to be fulfilled.

V. Joint Control

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

VI. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 20. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates, or timing could have a material impact on the carrying amount of the provision.

VIII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience, and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence, and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 3(A)(II).

IX. Employee Future Benefits

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

The liability for pension and post-employment benefits and associated costs included in annual compensation expenses are impacted by estimates related to:

- employee demographics, including age, compensation levels, employment periods, the level of contributions made to the plans, and earnings on plan assets,
- the effects of changes to the provisions of the plans, and
- changes in key actuarial assumptions, including rates of compensation and health-care cost increases, and discount rates.

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 27 for disclosures on employee future benefits.

X. Other Provisions

Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation, and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 20 with respect to other provisions.

3. Accounting Changes

A. Current Accounting Changes

I. Operating and Reportable Segments

During the first quarter, the Corporation disaggregated presentation of the previous Gas reportable segment into its two operating segments: Canadian Gas and Australian Gas. Previously included legacy costs of the non-operating U.S. Gas function have been reallocated to U.S. Coal to align with management's internal monitoring practices. Comparative segmented results for 2015 and 2014 have been restated to align with separate reporting of the two segments and the reallocation of the non-operating costs.

II. Change in Estimates – Useful Lives

As a result of the Alberta Off-Coal Arrangement described in Note 4(A), the Corporation will cease coal-fired emissions by the end of 2030. On Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with the Alberta coal assets were reduced to 2030. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

The Corporation entered into a Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") for the Mississauga plant in December 2016 as described in Note 4(D). As a result, the useful life of the plant was shortened to the end of 2016.

B. Future Accounting Changes

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

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property, and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted. IFRS 15 will be applied by the Corporation on Jan. 1, 2018.

The Corporation has created an implementation plan and is currently in the process of reviewing its various revenue streams and underlying contracts with customers to determine the impact that the adoption of IFRS 15 will have on its financial statements. The Corporation's implementation plan includes an assessment of the impacts on processes and controls which may be significant. Based on the Corporation's initial scoping assessment, we have identified sources of revenue that are accounted for as leases or financial instruments that are excluded from the scope of IFRS 15. Thus, the Corporation is currently focusing efforts on evaluating the effect of IFRS 15 on revenue contracts such as the Corporation's long-term electricity and thermal contracts, contracts for the sale of renewable attributes, merchant power revenue, and contracts for the sale of generation byproducts. Once the Corporation has developed the necessary accounting policies, estimates, judgments and processes with respect to the Corporation's revenue streams, the incremental compilation of historical data to make reasonable quantitative estimates of the effects of the new standard will commence. The Corporation has made progress on the implementation plan for IFRS 15 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 15 on the Corporation's financial statements and disclosures.

The Corporation's current estimate of the time and effort necessary to complete our implementation plan for IFRS 15 extends into mid to late 2017. The Corporation anticipates finalizing a decision with respect to our transition method by mid-2017.

II. IFRS 9 *Financial Instruments*

In July 2014, on completion of the impairment phase of the project to reform accounting for financial instruments and replace IAS 39 *Financial Instruments: Recognition and Measurement*, the IASB issued the final version of IFRS 9 *Financial Instruments*. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets (i.e., recognition of credit losses), and a new hedge accounting model. IFRS 9 is effective for annual periods beginning on or after Jan. 1, 2018 with early application permitted. IFRS 9 will be applied by the Corporation on Jan. 1, 2018.

Under the classification and measurement requirements, financial assets must be classified and measured at either amortized cost, at fair value through profit or loss, or through OCI, depending on the basis of the entity's business model for managing the financial asset and the contractual cash flow characteristics of the financial asset. The classification requirements for financial liabilities are unchanged from IAS 39. IFRS 9 requirements address the problem of volatility in net earnings arising from an issuer choosing to measure certain liabilities at fair value and require that the portion of the change in fair value due to changes in the entity's own credit risk be presented in OCI, rather than within net earnings.

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

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

The Corporation has created an implementation plan and is currently in the process of reviewing its various types of financial instruments to determine the potential impact. The Corporation's implementation plan includes an assessment of the impacts on processes and controls that may be significant. Based on our initial assessments, the Corporation anticipates financial statement impacts resulting from the implementation of the expected loss impairment model. The assessment of the financial statement impacts of implementing the classification and measure of financial assets and liabilities and hedge accounting model under IFRS 9 are ongoing. The Corporation has made progress on the implementation plan for IFRS 9 during 2016; however, it is not yet possible to make a reliable estimate of the impact of IFRS 9 on our financial statements and disclosures. The Corporation's current estimate of the time and effort necessary to complete our implementation plan for IFRS 9 extends into mid to late 2017.

III. IFRS 16 *Leases*

In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019, with early application permitted if IFRS 15 is also applied at the same time. The standard is required to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by the Corporation on Jan. 1, 2019.

The Corporation is in the process of completing its initial scoping assessment and expects to have an implementation plan in place by mid-2017. We anticipate most the effort under the implementation plan will occur in late 2017 through mid-2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on the Corporation's financial statements and disclosures.

C. Comparative Figures

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

4. Significant Events

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an agreement with the Government of Alberta (the "Government") on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the Off-Coal Agreement ("OCA"), the Corporation will receive annual cash payments of approximately $37.4 million, net to the Corporation, commencing in 2017 and terminating in 2030. Receipt of the payments is subject to certain terms and conditions. The Off-Coal Agreement's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. Other conditions include: maintaining prescribed spending on investment and investment related activities in Alberta; maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels); and maintaining spending on programs and initiatives to support the communities surrounding the plants, the employees of the Corporation negatively impacted by the phase-out of coal generation, and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

The Corporation entered into a Memorandum of Understanding with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas fired conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market to be developed for the Province of Alberta.

B. Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million. The buyer and the Balancing Pool are seeking to appeal or set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. TransAlta is opposing these steps and believes they are without merit. No provision has been recognized with respect to this.

C. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP ("TAPCLP"), which holds the Corporation's interest in the Poplar Creek cogeneration facility, completed the private placement of a $202.5 million aggregate principal amount of senior secured floating rate bonds. The bonds, which mature on Dec. 31, 2030, are secured by a first ranking charge over the equity interests of the issuer that issued such bonds. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points. The interest rate for the initial period commencing on the date of issue and ending on Dec. 31, 2016 is 4.828% per annum.

D. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the NUG Contract with the Ontario's Independent Electricity System Operator (the "IESO)" for its Mississauga cogeneration facility. The NUG Contract is effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated December 2018.

The NUG Contract provides the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations, and maintains the Corporation's operational flexibility to pursue opportunities for the facility to meet power market needs in northeastern Ontario. Further details on the NUG Contract and its impact to these financial statements can be found in Note 8.

E. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation has recorded an impairment charge of $28 million, included in the Wind and Solar segment.

F. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables Inc.'s ("TransAlta Renewables") subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

G. Investment in and Acquisition by TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm, and Ragged Chute Hydro Facility (the "Canadian Assets")

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 megawatts ("MW") of highly contracted power generation assets located in Ontario and Québec. The transaction was originally announced on Nov. 23, 2015.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million, and issued a $215 million convertible unsecured subordinated debenture. The debenture issued by TransAlta Renewables to the Corporation is on an interest-only basis at a coupon of 4.5 per cent per annum payable semi-annually in arrears on June 30 and December 31, and will mature on Dec. 31, 2020. On the maturity date, the Corporation will have the right, at its sole option, to convert the outstanding principal amount of the debenture, in whole or in part, into common shares of TransAlta Renewables at a conversion price of $13.16 per common share, being a 35 per cent premium to the offering price on the closing date of the investment in the Canadian Assets. If TransAlta does not exercise its conversion option, TransAlta Renewables may satisfy the principal obligation by issuing common shares with a unit value corresponding to 95 per cent of its then-current common share value.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million, through the issuance of a non-interest bearing loan payable to the Corporation.

The acquisition of the Canadian Assets was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the Canadian Assets' assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at Nov. 30, 2016, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $38 million.

H. Restructured Poplar Creek Contract and Acquisition of Wind Farms

On Sept. 1, 2015, the Corporation and Suncor Energy ("Suncor") restructured their arrangement for power generation services at Suncor's oil sands base site near Fort McMurray, Alberta.

The Corporation's Poplar Creek cogeneration facility, which has a maximum capacity of 376 MW, had been built and contracted to provide steam and electricity to Suncor until 2023 and is recorded in the gas segment. Under the terms of the new arrangement, Suncor acquired from TransAlta two steam turbines with an installed capacity of 132 MW and certain transmission interconnection assets. The Corporation retained two gas turbines and heat recovery steam generators ("gas generators"), which are leased to Suncor. Suncor assumed full operational control of the cogeneration facility, including responsibility for all capital costs, and has the right to use the full 244 MW capacity of the Corporation's gas generators until Dec. 31, 2030. The Corporation provides Suncor with centralized monitoring, diagnostics, and technical support to maximize performance and reliability of plant equipment. Ownership of the entire Poplar Creek cogeneration facility will transfer to Suncor in 2030. As the new contract was determined to constitute a finance lease, the full carrying amounts of the facility were derecognized.

As part of the transaction, the Corporation acquired Suncor's interest in two wind farms: the 20 MW Kent Breeze facility located in Ontario and Suncor's 51 per cent interest in the 88 MW Wintering Hills facility located in Alberta. The Corporation's interest in the Wintering Hills facility was accounted for as a joint operation. At Dec. 31, 2016, the Wintering Hills facility is classified as assets held for sale (see Note 4(E)).

The following table outlines the impacts of the transaction on closing in 2015, including assets and liabilities disposed of and the fair value of assets acquired and liabilities assumed:

Assets	
Finance lease receivable(1)	372
Property, plant, and equipment	104
Intangibles	37
Net working capital	2
Total assets acquired	**515**
Liabilities	
Decomissioning and restoration provision	3
Net assets acquired	**512**
Consideration transferred	
Property, plant, and equipment	234
Net working capital	27
Decommissioning and restoration provision	(11)
Carrying amount of transferred net assets	**250**
Gain recognized	**262**

(1) Future payments under the finance lease include $57 million annually from 2016 to 2018, and $20 million annually from 2019 to 2030. Payments have been discounted at a rate of 2.68%, based on comparative yield on borrowings of the counterparty with equivalent maturities at the time of closing.

The acquired wind farms' contribution to the Corporation's revenue and operating income since the date of acquisition until Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the wind farms would have contributed $8 million to revenues and reduced earnings before taxes by $2 million.

I. U.S. Solar and Wind Acquisition

On Oct. 1, 2015, the Corporation closed the acquisition of 100 per cent of the membership interests of Odin Wind Power LLC, owner of the 50 MW Lakeswind wind facility located in Minnesota, for cash consideration of $49 million and the assumption of certain tax equity obligations. The facility is contracted under long-term power purchase agreements until 2034.

On Sept. 1, 2015, the Corporation closed the acquisition of 100 per cent of the membership interests of RC Solar LLC for cash consideration of $55 million. The assets acquired include 21 MW of fully contracted solar projects located in Massachusetts, which are contracted under long-term power purchase agreements ranging from 20 to 30 years, and are qualified under phase one of the Massachusetts Solar Renewable Energy Credit program.

At the 2015 acquisition dates, the fair values of the identifiable assets and liabilities of Odin Wind Power LLC and RC Solar LLC were as follows:

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

(1) The Corporation has recognized a corresponding deferred tax recovery in the Consolidated Statement of Earnings upon acquisition, representing deductible temporary differences now expected to be recovered.

The acquired assets' contribution to the Corporation's revenue and operating income since the date of acquisition until the end of Dec. 31, 2015, was nominal. Had the acquisition taken place at the beginning of 2015, the assets would have contributed $14 million to revenues and reduced earnings before taxes by $6 million.

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

On May 7, 2015, the Corporation closed the acquisition by TransAlta Renewables of an economic interest based on the cash flows of the Corporation's Australian assets. The Corporation's Australian assets consist of 575 MW of power generation from six operating assets and the South Hedland power project currently under construction, as well as the recently commissioned 270-kilometre gas pipeline. TransAlta Renewables' investment consists of the acquisition of securities that, in aggregate, provide an economic interest based on cash flows of the Australian assets broadly equal to the underlying net distributable profits. The combined value of the transaction was $1.78 billion. The Corporation continues to own, manage, and operate the Australian assets.

With the closing of the transaction, the Corporation received net cash proceeds of $211 million as well as approximately $1,067 million through a combination of common shares and Class B shares of TransAlta Renewables. The Class B shares provide voting rights equivalent to the common shares, are non-dividend paying, and will convert into common shares once the South Hedland power project is completed and commissioned.

The number of common shares that the Corporation will receive on the conversion of the Class B shares will be adjusted to reflect the actual amount funded by TransAlta Renewables for the construction and commissioning of the South Hedland power project relative to target costs of $491 million.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,858,423 common shares at a price of $12.65 per share. The offering closed in two parts on April 15 and 23, 2015. TransAlta Renewables shareholder approval was received on May 7, 2015. TransAlta Renewables received approximately $226 million in gross proceeds, and in total, incurred $11 million in share issue costs, net of $3 million of income tax recovery. Proceeds to equity were further reduced by dividend-equivalent payments of $1 million.

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

On Nov. 26, 2015, the Corporation completed the sale to Alberta Investment Management Corporation ("AIMCo") of 20,512,820 common shares of TransAlta Renewables for gross proceeds of $200 million (net proceeds of $193 million). As a result, TransAlta's ownership interest was reduced from approximately 76.1 per cent to approximately 66.6 per cent (including the Class B common shares).

As part of the AIMCo investment, TransAlta Renewables granted to AIMCo a pre-emptive right to purchase such number of common shares of TransAlta Renewables in respect of any future offerings of common shares, or securities convertible into common shares, in order to allow AIMCo to maintain its proportionate shareholdings in TransAlta Renewables, provided that AIMCo's ownership remains above a specific threshold.

L. Restructuring Provision

On Jan. 14, 2015, the Corporation initiated a significant cost-reduction initiative at its Canadian Coal power generation operations, resulting in the elimination of positions. On Sept. 29, 2015, the Corporation further reduced its overhead costs by eliminating positions primarily at its corporate head office in Calgary.

M. Changes in Internal Capitalization of U.S. Entities

On Dec. 15, 2015, the Corporation partially redeemed its net investment in a wholly owned subsidiary. As a result, the Corporation reclassified from OCI pro rata cumulative translation gains of $10 million, offset by related pro rata cumulative after-tax losses of $6 million from the net investment hedge.

N. Disposal of CE Generation, LLC

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

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

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

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	2016		2015		2014	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**755**	**-**	775	-	937	-
Coal inventory writedown (recovery)	**(4)**	**-**	22	-	19	-
Purchased power	**143**	**-**	147	-	75	-
Mine depreciation	**63**	**-**	59	-	56	-
Salaries and benefits	**6**	**249**	5	250	5	280
Other operating expenses	**-**	**240**	-	242	-	262
Total	**963**	**489**	1,008	492	1,092	542

6. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets extending to the last planned asset retirement in 2073.

A. 2016

In 2016, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section III below.

During 2016, uncertainty continued to exist within the province of Alberta regarding the government's previously announced Climate Leadership Plan and the future design parameters of the electricity market. Additionally, economic conditions, while more stable than in 2015, contributed to continued over-supply conditions and depressed market prices. The Corporation assessed whether these factors presented an indicator of impairment for its Alberta Merchant CGU, and in consideration of the composition of this CGU and events arising during the latter part of 2016, which are more fully discussed below in I, determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, the Corporation did not perform an in-depth impairment analysis, but sensitivities associated with these factors were performed to confirm the continued existence of an adequate excess of estimated recoverable amount over net book value.

Through the Corporation's ongoing monitoring of potential factors, such as market, economic, and operating conditions, in other jurisdictions in which its plants operate, it concluded that no indicators of impairment were present as related to its other plants.

There was one impairment charge of $28 million related to the Wintering Hills facility (see Note 4(E) and III below) and no reversals of impairment made during the year ended Dec. 31, 2016.

I. Alberta Merchant CGU

In 2015, the Government of Alberta announced its Climate Leadership Plan ("CLP"), which broadly called for the phase-out of coal-generated electricity by 2030, and proposed the imposition of additional compliance obligations for greenhouse gas ("GHG") emissions in the province. In 2016, the Alberta government refined its approach to GHG by instituting a levy on carbon emissions in excess of defined limits, amounting to $20 per tonne in 2017 and $30 per tonne in 2018. At the federal level, the Canadian government announced its intention to implement a national price on greenhouse gas emissions. Under this proposal, beginning in 2018, there would be a price of $10 per tonne of carbon dioxide equivalent emitted, rising to $50 per tonne by 2022.

On Nov. 24, 2016, the Corporation reached an Off-Coal Agreement with the Alberta government to receive annual cash payments of approximately $37.4 million, net to the Corporation (see Note 4(A) for further details) in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, the Corporation entered into a Memorandum of Understanding (the "MOU") on Nov. 24, 2016, with the purpose of collaborating and co-operating to advance objectives of the Alberta Climate Leadership Plan. Specifically, the parties undertook to collaborate on, among other things:

- a move toward a capacity market, commencing in 2021, compared to the current energy-only market. Under a capacity market, generators are compensated for their available capacity;
- development of a policy and to facilitate the economic conversion of some coal-fired generation to natural-gas-fired generation in Alberta, including securing regulatory co-operation from the federal government; and
- policy development to address the value of carbon reductions in the generation of electricity from existing wind and hydro production, the development of effective supporting mechanisms to ensure that existing renewable generation is not adversely impacted by the implementation of a capacity market in Alberta, and the development of regulatory clarity and alignment so as to permit the economic and timely development of hydroelectric projects within Alberta.

The MOU does not create any legally binding obligations between the Alberta government and the Corporation and does not impose any obligations on, or constrain the discretion and authority of the Alberta government. The announcement of the intention to move to a capacity market is expected to impact the Alberta market mechanisms. The Alberta government has not provided further detail on the market rules or construct. The introduction of a capacity market to replace Alberta's current market structure could impact the Corporation's determination of the Alberta Merchant CGU; however, there is not currently sufficient information from the Alberta Government to determine if a change is required. The Corporation has not modified its previous conclusions on the determination of the Alberta Merchant CGU.

During the year, the Corporation monitored the potential impacts of the CLP and other announcements on the Alberta CGU. A sensitivity analysis on these estimates to assess potential impacts of the Alberta and federal government policies on the carbon levy and GHG emissions, as well as the impacts of the Off-Coal Agreement and MOU. The analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU due to the Corporation's large merchant renewable fleet in the province.

II. Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million (see Note 4(E)). In connection with this sale, the Wintering Hills assets were accounted for as held for sale at December 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal.

III. U.S. Coal

The Corporation considered possible impairment at the U.S. Coal CGU utilizing a similar process as noted in the 2014 section below, and again found that the fair value less costs to sell approximates the current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$22.00 to US$46.00 per MWh
On-highway diesel fuel on coal shipments	US$1.69 to US$2.09 per gallon
Discount rates	5.4 to 5.7 per cent

B. 2015

In 2015, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section II below.

During 2016, uncertainty existed within the province of Alberta regarding the government's announced Climate Leadership Plan. Additionally, economic conditions contributed to continued over-supply conditions and depressed market prices. The Corporation assessed whether these factors presented an indicator of impairment for its Alberta Merchant CGU, and determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. See section I below for further assessment.

There were no impairment charges and one reversal of $2 million made during the year ended Dec. 31, 2015.

I. Alberta Merchant CGU

The slowdown in the oil and gas sector put Alberta into a recession, and placed downward pressure on demand as well as power prices. Further, on Nov. 20, 2015, the Government of Alberta announced its Climate Leadership Plan, which broadly calls for the phase-out of coal-generated electricity by 2030, and proposes the imposition of additional compliance obligations for GHG emissions in the province.

During the fourth quarter of 2015, the Corporation completed a sensitivity analysis on the estimates for the Alberta Merchant CGU to assess potential impacts of the proposed Alberta government policy on reducing GHG emissions, as well as the mandatory retirement of coal facilities by 2030. The sensitivity demonstrated an approximate fair value substantially in excess of the carrying amount of the Alberta Merchant CGU, and accordingly, no further test was performed. The excess is attributable to the Corporation's large renewable fleet in the province.

II. U.S. Coal

The Corporation considered possible impairment at the U.S. Coal CGU utilizing a similar process as noted in the 2014 section below, and again found that the fair value, less costs to sell approximates the current carrying amount. The Corporation estimated the fair value less costs of disposal of the CGU, a Level III fair value measurement, utilizing the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$24.00 to US$50.00 per MWh
On-highway diesel fuel on coal shipments	US$2.44 to US$2.90 per gallon
Discount rates	5.2 to 6.2 per cent

III. Centralia Gas

Impairment reversals of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

B. 2014

In 2014, the Corporation concluded that an indicator of possible impairment existed with respect to its U.S. Coal facility as the plant has merchant exposure and price expectations in the Pacific Northwest region continued to decline. The results of the impairment analysis are outlined in section I below.

I. U.S. Coal

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

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

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

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

II. Centralia Gas

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

7. Finance Lease Receivables

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

As at Dec. 31	2016		2015	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**124**	**119**	121	116
Second to fifth years inclusive	**376**	**291**	414	326
More than five years	**637**	**311**	714	337
	1,137	**721**	1,249	779
Less: unearned finance lease income	**592**	**-**	648	-
Add: unguaranteed residual value	**233**	**57**	229	51
Total finance lease receivables	**778**	**778**	830	830

Included in the Consolidated Statements of Financial Position as:	2016	2015
Current portion of finance lease receivables *(Note 12)*	**59**	55
Long-term portion of finance lease receivables	**719**	775
	778	830

8. Net Other Operating (Income) Losses

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

Year ended Dec. 31	2016	2015	2014
Mississauga cogeneration facility NUG Contract	(191)	-	-
MSA settlement	-	56	-
Insurance recoveries	(3)	(31)	(10)
California claim	-	-	5
Supplier settlement	-	-	(9)
Net other operating (income) losses	**(194)**	25	(14)

A. Mississauga Cogeneration Facility Contract

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the Ontario IESO for its Mississauga cogeneration facility. The contract is effective on Jan. 1, 2017. The Corporation has agreed to terminate the existing contract with the Ontario Electricity Financial Corporation early, which would have otherwise terminated in December 2018.

As a result of the NUG Contract, the Corporation recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling approximately $16 million. The Corporation also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. The Corporation released and recognized in earnings unrealized pre-tax net losses of $14 million from AOCI due to cash flow hedges de-designated for accounting purposes. The cash flow hedges were in respect of future gas purchases denominated in US dollars and expected to occur, between 2017 and 2018. In the fourth quarter of 2016, the forecasted gas consumption was no longer expected to occur which resulted in the cumulative loss on the hedging instrument being released from AOCI and recognized in earnings.

B. Settlement with the Market Surveillance Administrator

On March 21, 2014, the Alberta Market Surveillance Administrator (the “MSA”) filed an application with the Alberta Utilities Commission (the “AUC”) alleging, among other things, that TransAlta manipulated the price of electricity in the Province of Alberta when it took outages at certain of its coal-fired generating units in late 2010 and early 2011. The Corporation denied the MSA’s allegations. An oral hearing took place before the AUC in December 2014. A written argument was filed in February 2015. In May 2015, further submissions were filed on a recent Supreme Court of Canada decision relevant to expert evidence. On July 27, 2015, the AUC issued a decision finding, among other things, that (i) the Corporation’s actions in relation to four outage events at its coal-fired generating units, spanning 11 days in 2010 and 2011, restricted or prevented a competitive response from the associated PPA buyers and manipulated market prices away from a competitive market outcome and (ii) the Corporation breached applicable legislation by allowing one of its employees to trade while in possession of non-public outage records. The AUC also found that the MSA did not prove, on the balance of probabilities, that the Corporation breached applicable legislation on the basis that its compliance policies, practices, and oversight thereof, were inadequate and deficient.

This AUC decision marked the end of the first phase of the proceedings. TransAlta filed for leave to appeal the AUC decision with the Alberta Court of Appeal in August 2015. The second phase of the AUC proceedings was to consider what penalty the AUC might impose against the Corporation. On Sept. 30, 2015, TransAlta and the MSA reached an agreement to settle all outstanding proceedings before the AUC. The settlement, which is in the form of a consent order, was approved by the AUC on Oct. 29, 2015. Under the terms of the consent order, the Corporation will pay a total amount of $56 million that includes approximately $27 million as a repayment of economic benefit, $4 million to cover the MSA’s legal and related costs, and a $25 million administrative penalty. Of this amount, $31 million was paid in the fourth quarter of 2015, and the $25 million administrative penalty was paid in November of 2016. As a result of the approval, the Corporation discontinued the appeal of the AUC’s decision.

C. Insurance Recoveries

During 2016, the Corporation received $3 million in insurance recoveries (2015 - $31 million, 2014 - $10 million), of which $2 million (2015 - $6 million, 2014 - $6 million) relates to business interruption insurance claims and $1 million relates to claims for replacement and refurbishment of equipment for certain wind facilities (2015 – $7 million for Canadian Coal facilities).

In 2015 and 2014 the Corporation received $18 million and $4 million of insurance recoveries, respectively, relating to claims for the replacement and refurbishment for certain hydro facilities as a result of the flooding in Southern Alberta in 2013. Additionally, in 2015 and 2014, $12 million and $18 million, respectively, of insurance proceeds were received related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in 2013 and were accounted for as a reduction to period operations, maintenance, and administration costs.

D. California Claim

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

E. Supplier Settlement

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

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2016	2015	2014
Interest on debt	236	228	238
Capitalized interest *(Note 16)*	(16)	(9)	(3)
Loss on redemption of bonds *(Note 10)*	1	-	-
Interest on finance lease obligations	3	4	1
Other	(5)	(2)	(1)
Keephills 1 outage interest accruals (reversals) *(Note 4)*	(10)	9	1
Accretion of provisions *(Note 20)*	20	21	18
Net interest expense	229	251	254

10. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2016	2015	2014
Earnings before income taxes	314	221	239
Net earnings attributable to non-controlling interests not subject to tax	(109)	(34)	(37)
Adjusted earnings before income taxes	205	187	202
Statutory Canadian federal and provincial income tax rate (%)	26.7	25.9	25.0
Expected income tax expense	55	48	51
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	(16)	(16)	(3)
Deferred income tax expense related to temporary difference on investment in subsidiary	11	95	-
MSA settlement	-	14	-
Reversal of writedown of deferred income tax assets	(10)	(56)	(5)
Statutory and other rate differences	1	20	-
Resolution of uncertain tax matters	-	-	(1)
Divestiture of investment	-	-	(38)
Other	(3)	-	3
Income tax expense	38	105	7
Effective tax rate (%)	19	56	3

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2016	2015	2014
Current income tax expense	23	24	33
Adjustments in respect of current income tax of previous years	-	(5)	-
Adjustments in respect of deferred income tax of previous years	(3)	5	2
Deferred income tax expense related to the origination and reversal of temporary differences	16	22	12
Deferred income tax expense related to temporary difference on investment in subsidiary(1)	11	95	-
Deferred income tax expense resulting from changes in tax rates or laws(2)	1	20	-
Benefit arising from previously unrecognized tax loss, tax credit, or temporary difference of a prior period used to reduce deferred income tax expense	-	-	(35)
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets(3)	(10)	(56)	(5)
Income tax expense	38	105	7

Year ended Dec. 31	2016	2015	2014
Current income tax expense	23	19	33
Deferred income tax expense (recovery)	15	86	(26)
Income tax expense	38	105	7

(1) In 2016, reorganizations of certain TransAlta subsidiaries were completed in connection with the New Richmond project financing and the disposition of the Canadian Assets to TransAlta Renewables. The reorganizations resulted in the recognition of deferred tax liabilities of $3 million and $8 million, respectively. In 2015, in order to give effect to the sale of an economic interest in the Australian assets to TransAlta Renewables, a reorganization of certain TransAlta subsidiaries was completed. The reorganization resulted in the recognition of a $95 million deferred tax liability on TransAlta's investment in a subsidiary. For both 2015 and 2016, the deferred tax liabilities had not been recognized previously, as prior to the reorganizations, the taxable temporary differences were not expected to reverse in the foreseeable future.

(2) 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016. 2015 relates to the impact of an increase in the Alberta corporate income tax rate from 10 per cent to 12 per cent, enacted June 18, 2015.

(3) During the year ended Dec. 31, 2016, the Corporation reversed a previous writedown of deferred income tax assets of $10 million (2015 - $56 million writedown reversal, 2014 - $5 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned U.S. operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned U.S. operations to utlize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2035. Recognized other comprehensive income during the years ended Dec. 31, 2016 and 2015 have given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2016	2015	2014
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	51	89	88
Net impact related to net investment hedges	16	8	(6)
Net actuarial gains (losses)	4	-	(7)
Share issuance costs	-	(4)	(1)
Loss on sale of investment in subsidiary	-	(8)	-
Income tax expense reported in equity	71	85	74

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2016	2015
Net operating loss carryforwards	768	822
Future decommissioning and restoration costs	103	91
Property, plant, and equipment	(1,114)	(1,124)
Risk management assets and liabilities, net	(282)	(250)
Employee future benefits and compensation plans	70	70
Interest deductible in future periods	90	91
Foreign exchange differences on U.S.-denominated debt	69	74
Deferred coal revenues	17	16
Other deductible temporary differences	3	(4)
Net deferred income tax liability, before writedown of deferred income tax assets	(276)	(214)
Writedown of deferred income tax assets	(383)	(362)
Net deferred income tax liability, after writedown of deferred income tax assets	(659)	(576)

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

As at Dec. 31	2016	2015
Deferred income tax assets(1)	53	71
Deferred income tax liabilities	(712)	(647)
Net deferred income tax liability	**(659)**	(576)

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

D. Contingencies

As of Dec. 31, 2016, the Corporation had recognized a net liability of $7 million (2015 - $7 million) related to uncertain tax positions. There were no changes in the liability for uncertain tax positions for the year ended Dec. 31, 2016.

11. Non-Controlling Interests

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

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2016
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	40.2% - Public shareholders
Kent Hills wind farm(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration L.P. ("TA Cogen")operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

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

A. TransAlta Renewables

The net earnings, distributions, and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 150 MW Kent Hills wind farm located in New Brunswick.

As a result of the transactions described in Note 4, the Corporation's share of ownership and equity participation in TransAlta Renewables has fluctuated since its formation as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Aug. 9, 2013 to April 28, 2014	80.7	80.7
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 and thereafter	64.0	59.8

As the Class B shares issued to the Corporation in the sale of the Australian assets were determined to constitute financial liabilities of TransAlta Renewables and do not participate in earnings until commissioning of South Hedland, they are excluded from the allocation of equity and earnings.

Year ended Dec. 31	**2016**	2015	2014
Revenues	**259**	236	233
Net earnings	**1**	198	52
Total comprehensive income	**40**	204	52
Amounts attributable to the non-controlling interests:			
Net earnings	**2**	63	15
Total comprehensive income	**18**	65	15
Distributions paid to non-controlling interests	**83**	43	28

As at Dec. 31	2016	2015
Current assets	109	74
Long-term assets	3,732	3,262
Current liabilities	(537)	(190)
Long-term liabilities	(1,237)	(1,120)
Total equity	(2,067)	(2,026)
Equity attributable to non-controlling interests	(851)	(787)
Non-controlling interests' share (per cent)	40.2	37.96

B. TA Cogen

Year ended Dec. 31	2016	2015	2014
Results of operations			
Revenues	274	288	305
Net earnings	211	61	71
Total comprehensive income	258	77	72
Amounts attributable to the non-controlling interest:			
Net earnings	105	31	35
Total comprehensive income	128	38	35
Distributions paid to Canadian Power Holdings Inc.	68	56	56

As at Dec. 31	2016	2015
Current assets	171	82
Long-term assets	538	535
Current liabilities	(65)	(75)
Long-term liabilities	(35)	(54)
Total equity	(609)	(488)
Equity attributable to Canadian Power Holdings Inc.	(301)	(242)
Non-controlling interest share (per cent)	49.99	49.99

12. Trade and Other Receivables

As at Dec. 31	2016	2015
Trade accounts receivable	558	433
Income taxes receivable	9	5
Current portion of finance lease receivables *(Note 7)*	59	55
Collateral paid *(Note 14)*	77	74
Trade and other receivables	703	567

13. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

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

Carrying value as at Dec. 31, 2016	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents[1]	-	-	305	-	305
Trade and other receivables	-	-	703	-	703
Long-term portion of finance lease receivables	-	-	719	-	719
Other assets	-	-	116	-	116
Risk management assets					
Current	192	57	-	-	249
Long-term	749	36	-	-	785
Financial liabilities			.		
Accounts payable and accrued liabilities	-	-	-	413	413
Dividends payable	-	-	-	54	54
Risk management liabilities					
Current	1	65	-	-	66
Long-term	4	44	-	-	48
Credit facilities, long-term debt and finance lease obligations[2]	-	-	-	4,361	4,361

(1) Includes cash equivalents of $103 million.

(2) Includes current portion.

Carrying value as at Dec. 31, 2015

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents	-	-	54	-	54
Trade and other receivables	-	-	567	-	567
Long-term portion of finance lease receivables	-	-	775	-	775
Risk management assets					
Current	101	197	-	-	298
Long-term	808	(11)	-	-	797
Financial liabilities					
Accounts payable and accrued liabilities	-	-	-	334	334
Dividends payable	-	-	-	63	63
Risk management liabilities					
Current	57	143	-	-	200
Long-term	45	24	-	-	69
Credit facilities, long-term debt and finance lease obligations(1)	-	-	-	4,495	4,495

(1) Includes current portion.

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level I, II, and III Fair Value Measurements

The Level I, II, and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation, and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as the Black-Scholes, mark-to-forecast, and historical bootstrap models with inputs that are based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical prices.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy, which governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of observable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses.

Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes, and shapes.

As at Dec. 31	2016		2015	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Long-term power sale - U.S.	907	+75 -69	863	+125 -186
Long-term power sale - Alberta	(3)	+5 -5	(13)	+13 -7
Unit contingent power purchases	13	+2 -4	(70)	+9 -8
Structured products - Eastern U.S.	24	+8 -8	18	+6 -4
Hydro slice products - Western U.S.	-	- -	(6)	+1 -4
Others	6	+3 -3	(3)	+2 -2

i. Long-Term Power Sale - U.S.

The Corporation has a long-term fixed price power sale contract in the U.S. for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2018, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high, and low power price scenarios. The base price forecast has been developed by averaging external fundamental based forecasts (providers are independent and widely accepted as industry experts for scenario and planning views). Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2016 are US$24 - US$40 (Dec. 31, 2015 - US$28 - US$45). The sensitivity analysis has been prepared using the Corporation's assessment that a US$5 price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2015 to Dec. 31, 2016, the base fair value and the sensitivity values have decreased by approximately $26 million and $2 million, respectively.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as held for trading.

For periods beyond 2021, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high, and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2016 are $55 - $107 (Dec. 31, 2015 - $86 - $93). The sensitivity analysis has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. Unit Contingent Power Purchases

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as held for trading.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2016 are 0.53 per cent to 0.94 per cent (Dec. 31, 2015 - 0 per cent to 2.8 per cent) and 8.41 per cent to 21.08 per cent (Dec. 31, 2015 – 1.7 per cent to 7.4 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 0.75 per cent and a change in volumetric discount rates of approximately 15.5 per cent, which approximate one standard deviation for each input.

iv. Structured Products - Eastern U.S.

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations, or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2016, are 66 per cent to 128 per cent and 42 per cent to 95 per cent (Dec. 31, 2015 – 85 per cent to 116 per cent and 65 per cent to 109 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 5 per cent and a change in non-standard shape factors of approximately 9 per cent, which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2016 are 18 per cent to 59 per cent and 63 per cent to 77 per cent (Dec. 31, 2015 – 18 per cent to 71 per cent and 39 per cent to 80 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities and correlation of approximately 10 per cent, respectively.

v. Hydro Slice Products – Western U.S.

The Corporation agreed to purchase power contingent upon the actual generation of specific hydro units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed capacity payment. The contracts were accounted for as held for trading and expired during the fourth quarter of 2016.

The key unobservable inputs used in the Dec. 31, 2015 valuations are delivered volume expectations. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements. This analysis is based on historical production of the generation units for available history. Volumes used in the Level III base fair value measurement at Dec. 31, 2015 are within the 50th percentile of the historical production.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

The following tables summarize the key factors impacting the fair value of the commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2016 and 2015, respectively:

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2015	-	(58)	640	-	128	(98)	-	70	542
Changes attributable to:									
Market price changes on existing contracts	-	44	163	-	(10)	13	-	34	176
Market price changes on new contracts	-	5	-	-	(23)	29	-	(18)	29
Contracts settled	-	20	(50)	-	(121)	88	-	(101)	38
Change in foreign exchange rates	-	1	(27)	-	-	-	-	1	(27)
Discontinued hedge accounting on certain contracts (see Note 4)	-	31	-	-	(31)	-	-	-	-
Net risk management assets (liabilities) at Dec. 31, 2016	-	43	726	-	(57)	32	-	(14)	758
Additional Level III information:									
Gains recognized in OCI			136			-			136
Total gains included in earnings before income taxes			50			42			92
Unrealized gains included in earnings before income taxes relating to net assets held at Dec. 31, 2016			-			130			130

	Hedges			Non-Hedges			Total		
	Level I	Level II	Level III	Level I	Level II	Level III	Level I	Level II	Level III
Net risk management assets (liabilities) at Dec. 31, 2014	-	(59)	314	-	180	(97)	-	121	217
Changes attributable to:									
Market price changes on existing contracts	-	(18)	261	-	49	(25)	-	31	236
Market price changes on new contracts	-	1	-	-	51	(48)	-	52	(48)
Contracts settled	-	26	(28)	-	(159)	76	-	(133)	48
Change in foreign exchange rates	-	(8)	93	-	7	(4)	-	(1)	89
Net risk management assets (liabilities) at Dec. 31, 2015	-	(58)	640	-	128	(98)	-	70	542
Additional Level III information:									
Gains recognized in OCI			354			-			354
Total gains (losses) included in earnings before income taxes			28			(77)			(49)
Unrealized losses included in earnings before income taxes relating to net liabilities held at Dec. 31, 2015			-			(1)			(1)

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2016, are primarily attributable to the following factors:

- changes in value of the long-term power sale contract (Level III hedge) as discussed in the preceding section (B)(I)(c)(i) of this note;
- change in value of Alberta power sale contracts and eastern Canadian gas purchase contracts (Level II hedge); and
- maturity of power contracts in the Northeast U.S. (Level II non-hedge) and maturities of unit contingent power purchases described in the section (B)(I)(c)(iii) of this note (Level III non-hedges).

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in hedging non-energy marketing transactions, such as interest rates, the net investment in foreign operations, and other foreign currency risks. Changes in other risk management assets and liabilities related to hedge positions are reflected within net earnings when such transactions have settled during the period or when ineffectiveness exists in the hedging relationship.

Other risk management assets and liabilities with a total net asset fair value of $176 million as at Dec. 31, 2016 (Dec. 31, 2015 - $214 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the period ended Dec. 31, 2016 are primarily attributable to the weakening of the US dollar relative to the Canadian dollar on the Corporation's foreign currency hedges.

IV. Other Financial Assets and Liabilities

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

	Fair value				Total carrying value
	Level I	Level II	Level III	Total	
Long-term debt(1) - Dec. 31, 2016	**-**	**4,271**	**-**	**4,271**	**4,221**
Long-term debt(1) - Dec. 31, 2015	-	4,067	-	4,067	4,344

(1) Includes current portion and excludes $67 million (Dec. 31, 2015 - $69 million) of debt measured and carried at fair value.

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

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

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this note for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	2016	2015	2014
Unamortized net gain at beginning of year	202	188	160
New inception gains	10	28	23
Change in foreign exchange rates	(4)	28	14
Amortization recorded in net earnings during the year	(60)	(42)	(9)
Unamortized net gain at end of year	**148**	202	188

14. Risk Management Activities

A. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2016	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	86	-	(16)	70
Long-term	-	683	-	(9)	674
Net commodity risk management assets (liabilities)	-	769	-	(25)	744
Other					
Current	-	105	-	8	113
Long-term	-	59	3	1	63
Net other risk management assets	-	164	3	9	176
Total net risk management assets (liabilities)	-	933	3	(16)	920

As at Dec. 31, 2015	Net investment hedges	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management					
Current	-	31	-	57	88
Long-term	-	551	-	(27)	524
Net commodity risk management assets	-	582	-	30	612
Other					
Current	(7)	20	-	(3)	10
Long-term	-	207	5	(8)	204
Net other risk management assets (liabilities)	(7)	227	5	(11)	214
Total net risk management assets (liabilities)	(7)	809	5	19	826

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

I. Netting Arrangements

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

As at Dec. 31	2016				2015			
	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	315	744	(113)	(53)	534	1,048	(350)	(93)
Gross amounts set-off	(24)	(3)	24	3	(105)	(12)	105	12
Net amounts as presented in the Consolidated Statements of Financial Position	291	741	(89)	(50)	429	1,036	(245)	(81)

II. Hedges

a. Net Investment Hedges

The Corporation's hedges of its net investment in foreign operations are comprised of US-dollar-denominated long-term debt with a face value of US$630 million (2015 - US$580 million) and the following foreign currency forward contracts:

As at Dec. 31	2016			2015			
Notional amount sold	Notional amount purchased	Fair value liability	Maturity	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign Currency Forward Contracts							
-	-	-	-	AUD297	CAD293	(6)	2016
-	-	-	-	USD76	CAD104	(1)	2016

During 2016, the Corporation de-designated its foreign currency forward contracts from its net investment hedges. The cumulative unrealized losses on these contracts will be deferred in AOCI until the disposal of the related foreign operation.

b. Cash Flow Hedges

i. Commodity Risk Management

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

As at Dec. 31	2016		2015	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	4,916	-	7,006	-
Natural gas *(GJ)*	-	-	-	22,485

During 2016, additional unrealized pre-tax gains of $nil (2015 - $3 million, 2014 - $2 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings. The cash flow hedges were in respect of future power production expected to occur between 2012 and 2017. In the first quarter of 2011, the production was assessed as highly probable not to occur based on then forecast prices. These unrealized gains were calculated using then current forward prices that changed between then and the time the contracts settled. Had these hedges not been deemed ineffective for accounting purposes, the revenues associated with these contracts would have been recorded in net earnings when settled, the majority of which occurred during 2012; however, the expected cash flows from these contracts would not change.

As at Dec. 31, 2016, cumulative gains of $4 million (2015 - $4 million) related to certain cash flow hedges that were previously de-designated and no longer meet the criteria for hedge accounting continue to be deferred in AOCI and will be reclassified to net earnings as the forecasted transactions occur or immediately if the forecasted transactions are no longer expected to occur.

ii. Foreign Currency Rate Risk Management

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

As at Dec. 31		2016			2015		
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
-	-	-	-	CAD138	USD126	36	2016-2018
AUD8	JPY710	1	2017	AUD19	JPY1,683	1	2016-2017
Foreign Exchange Forward Contracts - foreign-denominated debt							
CAD26	USD20	-	2018	CAD95	USD70	2	2016-2018
Cross-Currency Swaps - foreign-denominated debt							
CAD434	USD400	104	2017	CAD434	USD400	116	2017
CAD306	USD270	59	2018	CAD306	USD270	72	2018

iii. Effect of Cash Flow Hedges

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

Year ended Dec. 31, 2016					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	304	Revenue	(169)	Revenue	-
		Fuel and purchased power	44	Fuel and purchased power	31
Foreign exchange forwards on commodity contracts	(5)	Revenue	(16)	Revenue	(15)
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	-	Foreign exchange (gain) loss	-
Foreign exchange forwards on U.S. debt	(2)	Foreign exchange (gain) loss	53	Foreign exchange (gain) loss	-
Cross-currency swaps	(25)	Foreign exchange (gain) loss	(23)	Foreign exchange (gain) loss	-
Forward starting interest rate swaps	-	Interest expense	6	Interest expense	-
OCI impact	271	**OCI impact**	(105)	**Net earnings impact**	16

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminates the generation effective Jan. 1, 2017. Accordingly, the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 8(A) for further details.

During 2015 and 2014, total unrealized pre-tax gains of $6 million and $3 million, respectively, were released from AOCI and recognized in earnings due to hedge de-designations for accounting purposes.

Year ended Dec. 31, 2015					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
		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)

Over the next 12 months, the Corporation estimates that approximately $83 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

c. Fair Value Hedges

i. Interest Rate Risk Management

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.90 per cent (2015 - 6.65 per cent) to a floating interest rate based on the U.S. LIBOR rate using interest rate swaps as outlined below:

As at Dec. 31	2016		2015		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
USD50	**3**	**2018**	USD50	5	2018

Including interest rate swaps, 6 per cent of the Corporation's debt as at Dec. 31, 2016 is subject to floating interest rates (2015 - 9 per cent).

ii. Effects of Fair Value Hedges

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

Year ended Dec. 31		2016	2015	2014
Derivatives in fair value hedging relationships	**Location of gain (loss) recognized in earnings**			
Interest rate contracts	Net interest expense	**(2)**	(1)	(1)
Long-term debt	Net interest expense	**2**	1	1
Earnings (loss) impact		**-**	-	-

III. Non-Hedges

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as held for trading. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in earnings in the period the change occurs.

a. Commodity Risk Management

As at Dec. 31	2016		2015	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	19,362	19,060	42,975	38,565
Natural gas *(GJ)*	146,113	173,187	106,203	101,100
Transmission *(MWh)*	-	3,429	-	5,014
Emissions *(tonnes)*	1,370	1,370	960	960
Heating oil *(gallons)*	-	294	-	-

b. Other Non-Hedge Derivatives

As at Dec. 31		2016			2015		
Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign Exchange Forward Contracts							
USD152	CAD216	12	2017-2020	USD41	CAD54	(3)	2016-2018
AUD232	CAD219	(3)	2017-2020	AUD89	CAD79	(8)	2016-2020
-	-	-	-	AUD5	USD4	1	2016
Derivatives embedded in supplier contracts (1)							
-	-	-	-	USD4	AUD5	(1)	2016

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

c. Total Return Swaps

The Corporation has certain compensation, deferred, and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

d. Effect of Non-Hedges

For the year ended Dec. 31, 2016, the Corporation recognized a net unrealized loss of $63 million (2015 - loss of $51 million, 2014 - gain of $54 million) related to commodity derivatives.

For the year ended Dec. 31, 2016, a gain of $9 million (2015 - loss of $1 million, 2014 - gain of $10 million) related to foreign exchange and other derivatives was recognized and is comprised of net unrealized gains of $4 million (2015 - loss of $11 million, 2014 - gain of $2 million) and net realized gains of $5 million (2015 - gain of $10 million, 2014 - gain of $8 million).

B. Nature and Extent of Risks Arising from Financial Instruments

The following discussion is limited to the nature and extent of certain risks arising from financial instruments.

I. Market Risk

a. Commodity Price Risk

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

i. Commodity Price Risk – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue, and gain market information.

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

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

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

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2016, associated with the Corporation's proprietary trading activities was $2 million (2015 - $5 million, 2014 - $5 million).

ii. Commodity Price Risk - Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions, and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios, and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes.

As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2016, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $19 million (2015 - $24 million, 2014 - $27 million).

On asset-backed physical transactions, the Corporation's policy is to seek own use contract status or hedge accounting treatment. For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2016, associated with these transactions was $7 million (2015 - $1 million, 2014 - $7 million).

b. Interest Rate Risk

Interest rate risk arises as the fair value or future cash flows of a financial instrument can fluctuate because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The possible effect on net earnings and OCI due to changes in market interest rates affecting the Corporation's floating rate debt, interest-bearing assets, financial instruments measured at fair value through profit or loss, and hedging interest rate derivatives, is outlined below. The sensitivity analysis has been prepared using management's assessment that a 15 basis point (2015 - 15 basis point, 2014 - 15 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	2016		2015		2014	
	Net earnings increase(1)	OCI loss(1)	Net earnings increase(1)	OCI loss(1)	Net earnings increase(1)	OCI loss(1)
Basis point change	-	-	1	-	-	-

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

c. Currency Rate Risk

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

As part of the Australian assets transaction described in Note 4(J), the Corporation entered into foreign exchange hedging contracts with TransAlta Renewables to mitigate the risks to TransAlta Renewables shareholders of adverse changes in AUD in respect of AUD$239 million remaining investments to fund the South Hedland project. In addition, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in USD and AUD in respect of cash flows from the Australian assets in relation to the Canadian dollar for the first five years from the time of the Australian Assets Transaction. The financial effects of these contracts and agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years. Hedge accounting is not applied to these foreign currency contracts and accordingly, the loss on the contracts, recognized as a foreign exchange loss, was $5 million for the year ended Dec. 31, 2016 (2015 – loss $8 million).

The Corporation also uses foreign currency contracts to hedge its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

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

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average four cent (2015 and 2014 - four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2016		2015		2014	
Currency	Net earnings increase (decrease)(1)	OCI gain(1), (2)	Net earnings increase(1)	OCI gain(1), (2)	Net earnings decrease(1)	OCI gain(1), (2)
USD	(5)	-	2	5	4	5
AUD	(7)	-	(3)	-	(2)	-
Total	(12)	-	(1)	5	2	5

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

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

II. Credit Risk

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

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. In certain cases, the Corporation will require security instruments such as parental guarantees, letters of credit, cash collateral or third-party credit insurance to reduce overall credit risk. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2016:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables(1)	92	8	100	703
Long-term finance lease receivables(2)	36	64	100	719
Risk management assets(1)	100	-	100	1,034
Total				2,456

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

(2) The Corporation has one non-investment grade customer whose outstanding balance accounted for $445 million (Dec. 31, 2015 - $446 million). Risk of significant loss arising from this counterparty has been assessed as low in the near term, but could increase to moderate in an environment of sustained low commodity prices over the mid- to long term. The Corporation's assessment takes into consideration the counterparty's financial position, external rating assessments, how the Corporation provides its services in an area of the counterparty's lower-cost operations, and the Corporation's other credit risk management practices.

The Corporation's maximum exposure to credit risk at Dec. 31, 2016, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2016, was $14 million (2015 - $44 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's U.S. bonds one notch from Baa3 to Ba1. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. As at Dec. 31, 2016, TransAlta maintains investment grade ratings from three credit rating agencies. TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

Counterparties enter into certain commodity agreements, such as electricity and natural gas purchase and sale contracts, for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these agreements may contain credit-contingent features (such as downgrades in creditworthiness), which if triggered may result in the Corporation having to post collateral to its counterparties.

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

A maturity analysis of the Corporation's financial liabilities is as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Accounts payable and accrued liabilities	413	-	-	-	-	-	413
Long-term debt(1)	623	959	461	460	63	1,745	4,311
Commodity risk management assets	(69)	(73)	(80)	(79)	(100)	(343)	(744)
Other risk management (assets) liabilities	(114)	(67)	3	2	-	-	(176)
Finance lease obligations	16	14	10	8	6	19	73
Interest on long-term debt and finance lease obligations(2)	219	174	143	117	91	764	1,508
Dividends payable	54	-	-	-	-	-	54
Total	**1,142**	**1,007**	**537**	**508**	**60**	**2,185**	**5,439**

(1) Excludes impact of hedge accounting.

(2) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

C. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2016, the Corporation provided $77 million (2015 - $74 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is recorded in accounts receivable in the statement of financial position.

II. Financial Assets Held as Collateral

At Dec. 31, 2016, the Corporation held $21 million (2015 - $15 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations, or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is contained in accounts payable in the statement of financial position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2016, the Corporation had posted collateral of $116 million (Dec. 31, 2015 - $220 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $49 million (Dec. 31, 2015 - $44 million) of collateral to its counterparties.

15. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for Energy Marketing, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2016	2015
Parts and materials	110	116
Coal	65	56
Deferred stripping costs	12	14
Natural gas	17	8
Purchased emission credits	9	25
Total	**213**	219

The change in inventory is as follows:

Balance, Dec. 31, 2014	196
Net additions	47
Acquisition *(Note 4)*	10
Writedowns	(22)
Change in foreign exchange rates	(12)
Balance, Dec. 31, 2015	219
Net use	(12)
Writedowns	(9)
Reversal of writedowns	13
Change in foreign exchange rates	2
Balance, Dec. 31, 2016	**213**

No inventory is pledged as security for liabilities.

16. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2014	82	5,803	1,869	2,882	1,159	341	271	12,407
Additions	1	-	3	-	-	474	(2)	476
Acquisitions *(Note 4)*	-	-	-	321	-	-	-	321
Additions - finance lease	-	-	-	-	13	-	-	13
Disposals	(2)	-	(13)	-	-	-	-	(15)
Disposals - Poplar Creek *(Note 4)*	-	-	(429)	-	-	-	(7)	(436)
Impairment reversals *(Note 6)*	-	-	2	-	-	-	-	2
Revisions and additions to decommissioning and restoration costs	-	(42)	(10)	(21)	(13)	-	-	(86)
Retirement of assets	-	(106)	(19)	(18)	(11)	-	(4)	(158)
Change in foreign exchange rates	3	220	33	27	18	16	8	325
Transfers	11	216	48	74	42	(480)	94	5
As at Dec. 31, 2015	95	6,091	1,484	3,265	1,208	351	360	12,854
Additions	2	-	-	1	-	353	2	358
Additions - finance lease	-	-	-	-	7	-	-	7
Disposals	(1)	-	(3)	(1)	(1)	-	(3)	(9)
Impairment charges - Wintering Hills *(Note 4)*	-	-	-	(28)	-	-	-	(28)
Other *(Note 6)*	-	-	-	-	-	-	(1)	(1)
Revisions and additions to decommissioning and restoration costs	-	14	12	4	36	-	5	71
Retirement of assets	-	(96)	(3)	(14)	(6)	-	(3)	(122)
Change in foreign exchange rates	(1)	(38)	(16)	(10)	(3)	(13)	(4)	(85)
Reclassification to held for sale *(Note 4)*	-	-	-	(67)	-	-	-	(67)
Transfers [2]	-	(95)	51	62	24	(284)	37	(205)
As at Dec. 31, 2016	**95**	**5,876**	**1,525**	**3,212**	**1,265**	**407**	**393**	**12,773**
Accumulated depreciation								
As at Dec. 31, 2014	-	2,941	993	713	544	-	103	5,294
Depreciation	-	279	85	107	60	-	14	545
Retirement of assets	-	(96)	(15)	(12)	(7)	-	(4)	(134)
Disposals	-	-	(8)	-	-	-	-	(8)
Disposals - Poplar Creek *(Note 4)*	-	-	(202)	-	-	-	-	(202)
Change in foreign exchange rates	-	155	21	2	7	-	1	186
Transfers	-	1	(1)	-	-	-	-	-
As at Dec. 31, 2015	-	3,280	873	810	604	-	114	5,681
Depreciation	-	284	118	127	59	-	19	607
Retirement of assets	-	(85)	(4)	(7)	(2)	-	(3)	(101)
Disposals	-	-	(1)	-	(1)	-	-	(2)
Change in foreign exchange rates	-	(28)	(10)	-	(1)	-	-	(39)
Reclassification to held for sale *(Note 4)*	-	-	-	(6)	-	-	-	(6)
Transfers [2]	-	(239)	51	(2)	-	-	(1)	(191)
As at Dec. 31, 2016	**-**	**3,212**	**1,027**	**922**	**659**	**-**	**129**	**5,949**
Carrying amount								
As at Dec. 31, 2014	82	2,862	876	2,169	615	341	168	7,113
As at Dec. 31, 2015	95	2,811	611	2,455	604	351	246	7,173
As at Dec. 31, 2016	**95**	**2,664**	**498**	**2,290**	**606**	**407**	**264**	**6,824**

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

(2) Net transfers of $14 million relate to the transfer of gas equipment to finance lease receivables.

The Corporation capitalized $16 million of interest to PP&E in 2016 (2015 - $9 million) at a weighted average rate of 5.93 per cent (2015 – 5.83 per cent).

Finance lease additions in 2016 and 2015 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2016 was $76 million (2015 - $81 million).

17. Goodwill

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

As at Dec. 31	2016	2015
Hydro	259	259
Wind and Solar	175	176
Energy Marketing	30	30
Total goodwill	464	465

During 2015, the Corporation systemized allocations of certain costs to each fuel type within the broad generation segment. Accordingly, the Corporation disaggregated the generation segment into distinct generation segments as reportable segments. Accordingly, the Corporation re-allocated goodwill on a relative fair value basis in 2015. The Corporation allocated goodwill of the previous Canadian Renewables and Alberta Merchant group of CGUs to the Hydro and Wind and Solar segments and the previous U.S. Operations goodwill to the Wind and Solar segment on the basis of management's allocations for monitoring and performance measurement purposes. There were no changes made to the Energy Marketing goodwill.

For purposes of the 2016 and 2015 annual goodwill impairment review, the Corporation determined the recoverable amounts of the test units by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

The key assumption impacting the determination of fair value for the wind and solar and hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances, and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants, and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2016 models ranged between $32 to $301 per MWh during the forecast period (2015 - $26 to $311 per MWh). Discount rates used for the goodwill impairment calculation in 2016 ranged from 5.5 per cent to 6.0 per cent (2015 – 5.3 per cent to 6.5 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

18. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2014	178	206	186	34	604
Additions	-	1	-	25	26
Acquisitions *(Note 4)*	-	-	37	-	37
Retirements	-	(1)	-	-	(1)
Change in foreign exchange rates	-	8	-	-	8
Transfers	-	42	-	(44)	(2)
As at Dec. 31, 2015	178	256	223	15	672
Additions	**-**	**-**	**-**	**21**	**21**
Additions - capital lease	**-**	**3**	**-**	**-**	**3**
Retirements	**-**	**(3)**	**-**	**-**	**(3)**
Change in foreign exchange rates	**-**	**(1)**	**-**	**(1)**	**(2)**
Transfers	**-**	**13**	**-**	**(11)**	**2**
As at Dec. 31, 2016	**178**	**268**	**223**	**24**	**693**
Accumulated amortization					
As at Dec. 31, 2014	106	124	43	-	273
Amortization	3	20	9	-	32
Change in foreign exchange rates	-	3	-	-	3
Transfers	-	(5)	-	-	(5)
As at Dec. 31, 2015	109	142	52	-	303
Amortization	**6**	**24**	**8**	**-**	**38**
Retirements	**-**	**(3)**	**-**	**-**	**(3)**
As at Dec. 31, 2016	**115**	**163**	**60**	**-**	**338**
Carrying amount					
As at Dec. 31, 2014	72	82	143	34	331
As at Dec. 31, 2015	69	114	171	15	369
As at Dec. 31, 2016	**63**	**105**	**163**	**24**	**355**

19. Other Assets

The components of other assets are as follows:

As at Dec. 31	2016	2015
Deferred licence fees	**15**	16
Project development costs	**46**	42
Deferred service costs	**16**	17
Mississauga long-term receivable *(Note 4)*	**116**	-
Long-term prepaids and other	**44**	52
Keephills Unit 3 transmission deposit	**5**	6
Total other assets	**242**	133

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

Project development costs are primarily comprised of the Corporation's Sundance 7 and Dunvegan projects in Alberta. In December 2015, the Corporation repurchased its partner's 50 per cent share in TAMA Power, the jointly controlled entity developing the Sundance 7 project, for consideration of $10 million, payable in five years and an option for its partner to re-enter the development projects of TAMA Power at accumulated cost during this period.

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

Mississauga long-term receivable relates to amounts recognized as a result of entering into the new contract. Fixed monthly payments are to be received until Dec. 31, 2018. See Note 4 for further details.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Bill commitments presented in Note 32.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next five years to 2021, as long as certain performance criteria are met.

20. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2014	305	51	356
Liabilities incurred	6	58	64
Liabilities acquired	7	-	7
Liabilities settled	(24)	(14)	(38)
Liabilities disposed	(11)	(1)	(12)
Accretion	20	1	21
Revisions in estimated cash flows	1	71	72
Revisions in discount rates	(89)	-	(89)
Reversals	-	(2)	(2)
Change in foreign exchange rates	18	1	19
Balance, Dec. 31, 2015	233	165	398
Liabilities incurred	11	12	23
Liabilities settled	(23)	(36)	(59)
Accretion	19	1	20
Revisions in estimated cash flows	12	5	17
Revisions in discount rates	44	-	44
Reversals	-	(96)	(96)
Change in foreign exchange rates	(3)	(1)	(4)
Balance, Dec. 31, 2016	**293**	**50**	**343**

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2015	233	165	398
Current portion	30	136	166
Non-current portion	203	29	232
Balance, Dec. 31, 2016	**293**	**50**	**343**
Current portion	27	12	39
Non-current portion	266	38	304

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.1 billion, which will be incurred between 2017 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2016, the Corporation had provided a surety bond in the amount of US$139 million (2015 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2016, the Corporation had provided letters of credit in the amount of $117 million (2015 - $115 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Other Provisions

Other provisions include amounts related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used and for vacant leased premises. Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2023.

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

During 2015, the Corporation recorded a significant adjustment to other provisions, relating to the force majeure claim at Keephills 1. However, on Nov. 18, 2016, force majeure relief was granted to the Corporation and accordingly approximately $94 million was reversed during the last quarter of 2016 as disclosed in Note 4(B).

21. Credit Facilities, Long-Term Debt, and Finance Lease Obligations

A. Credit Facilities, Debt and Letters of Credit

The amounts outstanding are as follows:

As at Dec. 31	2016			2015		
	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	-	-	-	315	315	3.1%
Debentures	1,045	1,051	6.0%	1,044	1,051	6.0%
Senior notes[3]	2,151	2,158	5.0%	2,221	2,221	4.9%
Non-recourse[4]	1,038	1,048	4.5%	766	773	4.5%
Other[5]	54	54	9.2%	67	67	9.3%
	4,288	4,311		4,413	4,427	
Finance lease obligations	73			82		
	4,361			4,495		
Less: current portion of long-term debt	(623)			(72)		
Less: current portion of finance lease obligations	(16)			(15)		
Total current long-term debt and finance lease obligations	(639)			(87)		
Total credit facilities, long-term debt, and finance lease obligations	3,722			4,408		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2016 - US$1.6 billion (Dec. 31, 2015 - US$1.6 billion).
(4) Includes US$53 million at Dec. 31, 2016 (Dec. 31, 2015 - US$59 million).
(5) Includes US$29 million at Dec. 31, 2016 (Dec. 31, 2015 - US$36 million) of tax equity financing.

Credit facilities The $1.5 billion committed syndicated bank facility is the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected Canadian prime, bankers' acceptances, U.S. LIBOR, or U.S. base rate in accordance with a pricing grid that is standard for such facilities. The Corporation also has $240 million in committed bilateral credit facilities which expire in 2018 and a US$200 million committed bilateral credit facility expiring in 2020.

During 2016, the Corporation:

- paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian Assets that closed Jan. 6, 2016 (see Note 4);
- extended the four-year revolving $1.5 billion committed syndicated credit facility and three bilateral credit facilities by one year to 2020 and 2018, respectively, with key terms and covenants unchanged; and
- extended the four-year US$200 million bilateral credit facility to 2020. The amount available was reduced from US$300 million to US$200 million. The remaining key terms and covenants were unchanged.

Of the $2.0 billion (2015 - $2.2 billion) of committed credit facilities, $1.4 billion (2015 - $1.3 billion) is not drawn. The Corporation is in compliance with the terms of the credit facility and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, TransAlta also has $305 million of available cash and cash equivalents.

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2019 to 2030.

Senior notes bear interest at rates ranging from 1.90 per cent to 6.90 per cent and have maturity dates ranging from 2017 to 2040.

On Jan. 15, 2015, the Corporation's US$500 million 4.75 per cent senior notes matured and were paid out using existing liquidity.

A total of US$630 million (2015 - US$580 million) of the senior notes has been designated as a hedge of the Corporation's net investment in U.S. foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2017 to 2032 and bear interest at rates ranging from 2.95 per cent to 7.31 per cent.

During 2016:

- the Corporation's $27 million 5.69 per cent non-recourse debenture matured and was paid out using existing liquidity;
- the Corporation's subsidiary New Richmond Wind L.P. issued a non-recourse bond in the amount of $159 million, bearing interest at 3.963 per cent, with principal and interest payable semi-annually, and maturing on June 30, 2032 (see Note 4);
- the Corporation made a scheduled semi-annual $4.2 million principal payment on the New Richmond Wind L.P. bond;
- the Corporation made scheduled semi-annual principal payments of approximately $35 million on the Melancthon-Wolfe Wind L.P. bond;
- the Corporation's indirect wholly-owned subsidiary TAPC Holdings L.P. issued a non-recourse bond in the amount of $202.5 million, bearing a variable interest rate at the Canadian Dollar Offered Rate plus 395 basis points, with principal and interest payable quarterly, maturing on Dec. 31, 2030 (see Note 4), and;
- early redeemed $10 million of non-recourse bonds, which resulted in a $1 million loss recognized in interest expense.

During 2015:

- the Corporation and its partner issued non-recourse bonds secured by their jointly owned Pingston facility. The Corporation's share of gross proceeds was $45 million. The non-recourse bonds bear interest at the annual fixed interest rate of 2.95 per cent, payable semi-annually with no principal repayments until maturity in May 2023. Proceeds were used to repay the $35 million non-recourse debenture bearing interest at 5.28 per cent related to the Pingston facility.
- the Corporation's $120 million 5.33 per cent non-recourse debentures matured and were paid out using existing liquidity. The Corporation also closed the acquisition of solar assets (see Note 4) and assumed approximately US$42 million of non-recourse variable rate debt, of which approximately US$32 million is hedged to a fixed rate of 1.7 per cent.
- the Corporation's subsidiary Melancthon-Wolfe Wind L.P. issued a non-recourse bond in the amount of $442 million, bearing interest at 3.834 per cent, with principal and interest payable semi-annually in blended payments until maturity on Dec. 31, 2028.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financing assumed in the Lakeswind wind acquisition (see Note 4).

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2016, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt and Security

Non-recourse debentures of $193 million (2015 - $230 million) issued by the Corporation's subsidiary, CHD, include restrictive covenants requiring the cash proceeds received from the sale of assets to be reinvested into similar renewable assets or to repay the non-recourse debentures.

Other non-recourse debt of $845 million in total (2015 - $536 million) is subject to customary financing restrictions that restrict the Corporation's ability to access funds generated by certain facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. At Dec. 31, 2016, $24 million of cash was subject to these financial restrictions. Non-recourse debts of $644 million are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which includes renewable generation facilities with total carrying amounts of $956 million at Dec. 31, 2016 (2015 - $798 million). A non-recourse bond of approximately $201 million is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

C. Principal Repayments

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Principal repayments[1]	623	959	461	460	63	1,745	**4,311**

(1) Excludes impact of derivatives.

D. Finance Lease Obligations

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

As at Dec. 31	2016		2015	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	19	19	18	18
Second to fifth years inclusive	44	39	49	44
More than five years	21	15	29	20
	84	73	96	82
Less: interest costs	11	-	14	-
Total finance lease obligations	73	73	82	82

Included in the Consolidated Statements of Financial Position as:	2016	2015
Current portion of finance lease obligations	16	15
Long-term portion of finance lease obligations	57	67
	73	82

E. Letters of Credit

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2016 was $566 million (2015 - $575 million) with no (2015 - nil) amounts exercised by third parties under these arrangements.

22. Defined Benefit Obligation and Other Long-Term Liabilities

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

As at Dec. 31	2016	2015
Defined benefit obligation *(Note 27)*	208	222
Deferred coal revenues	62	60
Long-term incentive accruals *(Note 26)*	14	8
Other	46	58
Total	**330**	348

Deferred coal revenues consist of amounts received from the Corporation's Keephills Unit 3 joint operation partner for future coal deliveries. These amounts are being amortized into revenue over the life of the coal supply agreement, since commercial operations of Keephills Unit 3 began on Sept. 1, 2011.

Other includes $10 million (2015 - $11 million) relating to a reimbursement received for costs of the New Richmond terminal station, which is being amortized to revenue over the term of the related PPA.

23. Common Shares

A. Issued and Outstanding

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

As at Dec. 31	2016		2015	
	Common shares *(millions)*	Amount	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	284.0	3,077	275.0	3,001
Issued under the dividend reinvestment and share purchase plan	3.9	18	9.0	76
	287.9	3,095	284.0	3,077
Amounts receivable under Employee Share Purchase Plan	-	(1)	-	(2)
Issued and outstanding, end of year	**287.9**	**3,094**	284.0	3,075

B. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which has been revised since that time to ensure conformity with current practices. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 22, 2016. The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. When an acquiring shareholder commences a bid to acquire 20 per cent or more of the Corporation's common shares, other than by way of a "permitted bid" (as defined in the Shareholder Rights Plan), where the offer is made to all shareholders by way of a takeover bid circular, the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to acquire an additional $200 worth of common shares for $100.

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

On Feb. 21, 2012, the Corporation added a Premium Dividend™ Component to its existing dividend reinvestment plan. The amended and restated plan provided eligible shareholders with two options: i) to reinvest dividends at a current three per cent discount to the average market price towards the purchase of new common shares of the Corporation (the Dividend Reinvestment Component) or; ii) to receive a premium cash payment equivalent to 102 per cent of the reinvested dividends (the Premium Dividend™ Component).

The Corporation suspended the Premium Dividend™ Component of the Plan following the payment of the quarterly dividend on July 1, 2013. The Corporation's Dividend Reinvestment and Optional Common Share Purchase Plan, separate components of the Plan, remained effective in accordance with their current terms. On Jan. 14, 2016, the Corporation announced the suspension of the Premium Dividend™, Dividend Reinvestment and Optional Common Share Purchase Plan (the "DRIP"), in order to stop shareholder dilution.

On Jan. 1, 2016, 3.9 million common shares were issued for dividends reinvested.

D. Earnings per Share

Year ended Dec. 31	2016	2015	2014
Net earnings (loss) attributable to common shareholders	117	(24)	141
Basic and diluted weighted average number of common shares outstanding (millions)	288	280	273
Net earnings (loss) per share attributable to common shareholders, basic and diluted	0.41	(0.09)	0.52

E. Dividends

On Jan. 14, 2016, the Corporation announced the resizing of its dividend from $0.72 annually to $0.16 annually, as part of a plan to maximize the Company's long-term financial flexibility.

On Oct. 17, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2017.

On Dec. 19, 2016, the Corporation declared a quarterly dividend of $0.04 per common share, payable on April 1, 2017.

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

24. Preferred Shares

A. Issued and Outstanding

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

As at Dec. 31	2016		2015	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	10.2	248	12.0	293
Series B	1.8	45	-	-
Series C	11.0	269	11.0	269
Series E	9.0	219	9.0	219
Series G	6.6	161	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares conversion

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2016.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016 to but excluding March 31, 2021, if, as and when declared by the Board based on an annualized fixed dividend rate of 2.539 per cent, and will reset every quarter.

II. Preferred Share Series Information

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

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2016, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next Conversion Date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.79543	March 31, 2021	2.03	B
B	Floating	0.47608	March 31, 2021	2.03	A
C	Fixed	1.15	June 30, 2017	3.10	D
D	Floating	-	-	3.10	C
E	Fixed	1.25	Sept. 30, 2017	3.65	F
F	Floating	-	-	3.65	E
G	Fixed	1.325	Sept. 30, 2019	3.80	H
H	Floating	-	-	3.80	G

B. Dividends

The following table summarizes the preferred share dividends declared in 2016, 2015, and 2014:

	Total dividends declared ($)		
Series	**2016**	2015	2014
A	10	14	14
B	1	-	-
C	16	13	13
E	14	11	11
G	11	8	3
Total for the year	**52**	46	41

On Dec. 19, 2016, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.15651 per share on the Series B preferred shares, $0.2875 per share on the Series C preferred shares, $0.3125 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2017.

25. Accumulated Other Comprehensive Income

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

	2016	2015
Currency translation adjustment		
Opening balance, Jan. 1	52	(19)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax[(1)]	(71)	237
(Gains) losses on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[(2)]	18	(166)
Balance, Dec. 31	(1)	52
Cash flow hedges		
Opening balance, Jan. 1	350	173
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[(3)]	106	177
Balance, Dec. 31	456	350
Employee future benefits		
Opening balance, Jan. 1	(46)	(50)
Net actuarial gains on defined benefit plans, net of tax[(4)]	8	4
Balance, Dec. 31	(38)	(46)
Other		
Opening balance, Jan. 1	(3)	-
Intercompany available for sale investments	(15)	(3)
Balance, Dec. 31	(18)	(3)
Accumulated other comprehensive income	399	353

(1) Net of income tax expense of 11 for the year ended Dec. 31, 2016 (2015 - nil).
(2) Net of income tax expense of 5 for the year ended Dec. 31, 2016 (2015 - 8 expense).
(3) Net of income tax expense of 51 for the year ended Dec. 31, 2016 (2015 - 89 expense).
(4) Net of income tax expense of 4 for the year ended Dec. 31, 2016 (2015 - nil).

26. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

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

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

The pre-tax compensation expense related to PSUs and RSUs in 2016 was $17 million (2015 - $3 million reversal, 2014 - $8 million expense), which is included in operations, maintenance, and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $3 million in 2016 (2015 - $2 million reversal, 2014 - nil).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13.0 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance. The expense recognized relating to this grant during 2016 was less than $1 million.

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2016 are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	Number of options at Dec. 31, 2016 *(millions)*	Weighted average remaining contractual life *(years)*	Weighted average exercise price *($ per share)*
5.00 - 6.00	1.1	6.1	5.93
22.00 - 30.00[1]	0.6	3.1	23.60
31.00 - 48.00[1]	0.5	1.1	34.35
5.00 - 48.00	**2.2**	**4.2**	**28.93**

(1) Options currently exerciseable.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation extended interest-free loans (up to 30 per cent of an employee's base salary) to employees below executive level and allowed for payroll deductions over a three-year period to repay the loan. Executives were not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchased these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares were handled in the same manner. At Dec. 31, 2016, amounts receivable from employees under the plan totaled $1 million (2015 - $2 million).

On Jan. 14, 2016, the Corporation suspended its employee share purchase plan.

27. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the U.S. covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional supplemental defined benefit plan for certain employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and U.S. defined benefit pension plans are closed to new entrants. The U.S. defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned.

The latest actuarial valuations for accounting purposes of the Canadian and U.S. pension plans were at Dec. 31, 2015 and Jan. 1, 2016, respectively. The latest actuarial valuation for accounting purposes of the Highvale pension plan was at Dec. 31, 2013. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2016.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the U.S. The latest actuarial valuation for funding purposes of the Canadian registered plans was completed in early 2016 with an effective date of Dec. 31, 2015. The latest actuarial valuation for funding purposes of the U.S. pension plan was Jan. 1, 2016. As permitted by the regulators, the TransAlta Corporation pension plan uses a letter of credit to secure the required solvency special payments. The Corporation posted a letter of credit in the amount of $75 million for the annual period commencing in July 2016.

The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation has posted a letter of credit in the amount of $73 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and U.S. plans were as at Dec. 31, 2016 and Jan. 1, 2016, respectively. The measurement date used to determine the present value of the defined benefit obligation for both plans was Dec. 31, 2016.

The Corporation provides several defined contribution plans, including a U.S. 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

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

Year ended Dec. 31, 2016	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	-	-	(16)
Curtailment and amendment gain	-	-	-	-
Defined benefit expense	14	5	3	22
Defined contribution expense	15	-	-	15
Net expense	29	5	3	37

Year ended Dec. 31, 2015	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	-	-	(16)
Curtailment and amendment gain[(1)]	-	(5)	(3)	(8)
Defined benefit expense	14	-	-	14
Defined contribution expense	21	-	-	21
Net expense	35	-	-	35

(1) Relates to the reduction in the number of employees associated with the restructuring intative described in Note 4(L).

Year ended Dec. 31, 2014	Registered	Supplemental	Other	Total
Current service cost	6	2	2	10
Administration expenses	2	-	-	2
Interest cost on defined benefit obligation	23	4	1	28
Interest on plan assets	(18)	-	-	(18)
Defined benefit expense	13	6	3	22
Defined contribution expense	20	-	-	20
Net expense	33	6	3	42

C. Status of Plans

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

As at Dec. 31, 2016	Registered	Supplemental	Other	Total
Fair value of plan assets	423	10	-	433
Present value of defined benefit obligation	(554)	(82)	(27)	(663)
Funded status - plan deficit	(131)	(72)	(27)	(230)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(15)	(6)	(1)	(22)
Other long-term liabilities	(116)	(66)	(26)	(208)
Total amount recognized	(131)	(72)	(27)	(230)

As at Dec. 31, 2015	Registered	Supplemental	Other	Total
Fair value of plan assets	429	9	-	438
Present value of defined benefit obligation	(566)	(80)	(32)	(678)
Funded status - plan deficit	(137)	(71)	(32)	(240)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(11)	(5)	(2)	(18)
Other long-term liabilities	(126)	(66)	(30)	(222)
Total amount recognized	(137)	(71)	(32)	(240)

D. Plan Assets

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

	Registered	Supplemental	Other	Total
Fair value of plan assets as at Dec. 31, 2014	427	8	-	435
Interest on plan assets	16	-	-	16
Net return on plan assets	6	-	-	6
Contributions	12	7	1	20
Benefits paid	(36)	(6)	(1)	(43)
Administration expenses	(2)	-	-	(2)
Effect of translation on U.S. plans	6	-	-	6
Fair value of plan assets as at Dec. 31, 2015	429	9	-	438
Interest on plan assets	16	-	-	16
Net return on plan assets	10	-	-	10
Contributions	11	6	1	18
Benefits paid	(40)	(5)	(1)	(46)
Administration expenses	(2)	-	-	(2)
Effect of translation on U.S. plans	(1)	-	-	(1)
Fair value of plan assets as at Dec. 31, 2016	423	10	-	433

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

Year ended Dec. 31, 2016	Level I	Level II	Level III	Total
Equity securities				
Canadian	-	76	-	76
U.S.	-	30	-	30
International	-	120	-	120
Private	-	-	2	2
Bonds				
AAA	-	47	-	47
AA	-	58	-	58
A	-	55	-	55
BBB	1	22	-	23
Below BBB	-	5	-	5
Money market and cash and cash equivalents	3	14	-	17
Total	4	427	2	433

Year ended Dec. 31, 2015	Level I	Level II	Level III	Total
Equity securities				
Canadian	-	70	-	70
U.S.	-	32	-	32
International	-	120	-	120
Private	-	-	3	3
Bonds				
AAA	-	53	-	53
AA	-	57	-	57
A	1	60	-	61
BBB	1	21	-	22
Below BBB	-	4	-	4
Money market and cash and cash equivalents	4	12	-	16
Total	6	429	3	438

Plan assets do not include any common shares of the Corporation at Dec. 31, 2016 and Dec. 31, 2015. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2016 (2015 - $0.1 million).

E. Defined Benefit Obligation

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

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2014	565	86	30	681
Current service cost	7	2	2	11
Interest cost	21	3	1	25
Benefits paid	(36)	(6)	(1)	(43)
Actuarial gain arising from demographic assumptions	(1)	-	-	(1)
Actuarial loss arising from financial assumptions	3	2	2	7
Actuarial gain arising from experience adjustments	-	(2)	(2)	(4)
Curtailment and amendment	-	(5)	(3)	(8)
Effect of translation on U.S. plans	7	-	3	10
Present value of defined benefit obligation as at Dec. 31, 2015	566	80	32	678
Current service cost	7	2	2	11
Interest cost	21	3	1	25
Benefits paid	(40)	(5)	(1)	(46)
Actuarial loss arising from demographic assumptions	(1)	-	(4)	(5)
Actuarial gain arising from financial assumptions	2	-	-	2
Actuarial (gain) loss arising from experience adjustments	-	2	(2)	-
Effect of translation on U.S. plans	(1)	-	(1)	(2)
Present value of defined benefit obligation as at Dec. 31, 2016	**554**	**82**	**27**	**663**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2016 is 13.6 years.

F. Contributions

The expected employer contributions for 2017 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	15	6	1	22

G. Assumptions

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

	As at Dec. 31, 2016			As at Dec. 31, 2015		
(per cent)	Registered	Supplemental	Other	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	3.7	3.6	3.7	3.8	3.6	3.8
Rate of compensation increase	2.9	3.0	-	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	-	-	7.9(1)	-	-	7.8(3)
Dental care cost escalation	-	-	4.0	-	-	4.0
Provincial health care premium escalation	-	-	-	-	-	5.0
Benefit cost for the year						
Discount rate	3.8	3.8	3.8	3.8	3.8	3.8
Rate of compensation increase	3.0	3.0	-	3.0	3.0	-
Assumed health care cost trend rate						
Health care cost escalation	-	-	7.8(2)	-	-	7.5(4)
Dental care cost escalation	-	-	4.0	-	-	4.0
Provincial health care premium escalation	-	-	5.0	-	-	5.0

(1) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.

(2) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2024 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.

(3) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2024 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.

(4) Post- and Pre 65 rates: decreasing gradually to 5% by 2019-2020 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.35% per year to 5% in 2024 for Canada.

H. Sensitivity Analysis

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

	Canadian plans			U.S. plans	
Year ended Dec. 31, 2016	Registered	Supplemental	Other	Pension	Other
1% decrease in the discount rate	73	12	2	3	1
1% increase in the salary scale	9	1	-	-	-
1% increase in the health care cost trend rate	-	-	2	-	-
10% improvement in mortality rates	17	2	-	1	-

28. Joint Arrangements

Joint arrangements at Dec. 31, 2016 included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
Wintering Hills (1)	Wind	51	Wind generation facility in Alberta operated by TransAlta
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

(1) Classified as held for sale as at Dec. 31, 2016 (See Note 4(E)).

29. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2016**	2015	2014
(Use) source:			
Accounts receivable	**(23)**	(77)	59
Prepaid expenses	**5**	(3)	(1)
Income taxes receivable	**(4)**	1	1
Inventory	**11**	(9)	7
Accounts payable, accrued liabilities, and provisions	**81**	(152)	8
Income taxes payable	**3**	(2)	(1)
Change in non-cash operating working capital	**73**	(242)	73

30. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2016	2015	Increase/ (decrease)
Long-term debt[(1)]	**4,361**	4,495	**(134)**
Equity			
Common shares	**3,094**	3,075	**19**
Preferred shares	**942**	942	**-**
Contributed surplus	**9**	9	**-**
Deficit	**(933)**	(1,018)	**85**
Accumulated other comprehensive income	**399**	353	**46**
Non-controlling interests	**1,152**	1,029	**123**
Less: available cash and cash equivalents[(2)]	**(305)**	(54)	**(251)**
Less: fair value asset of hedging instruments on long-term debt[(3)]	**(163)**	(190)	**27**
Total capital	**8,556**	8,641	**(85)**

(1) Includes finance lease obligations, amounts outstanding under credit facilities, tax equity liability, and current portion of long-term debt.

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

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

In 2016, the Corporation focused on raising non-recourse debt to fund upcoming corporate debt maturities. The Corporation's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2015 and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios, and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

The Corporation has an investment grade credit rating from S&P (stable outlook), DBRS (negative outlook), and Fitch (negative outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook. During the first quarter of 2016, two rating agencies affirmed the Corporation's long-term issuer rating as investment grade, but revised their outlook to negative, from a previous stable outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Strengthening the Corporation's financial position allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results, and provides the Corporation with better access to capital markets through commodity and credit cycles.

As at Dec. 31	2016	2015	Target
Comparable funds from operations to adjusted interest coverage (times)	**3.8**	3.8	4 to 5
Adjusted comparable funds from operations to adjusted net debt (%)	**17.0**	15.2	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization (times)	**3.8**	5.0	3.0 to 3.5

Comparable Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as comparable FFO plus interest on debt (net of capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares. Comparable FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. Comparable FFO to adjusted interest coverage in 2016 is consistent with 2015. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted Comparable FFO to Adjusted Net Debt is calculated as comparable FFO less 50 per cent of dividends paid on preferred shares divided by net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents and including fair value assets of hedging instruments on debt). Adjusted comparable FFO to adjusted net debt increased in 2016 compared to 2015 due to the increase in comparable FFO, and lower debt due to repayments and the strengthening of the Canadian dollar in 2016. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable Earnings before Interest, Taxes, Depreciation, and Amortization ("EBITDA") is calculated as net debt divided by comparable EBITDA. Comparable EBITDA is calculated as earnings before interest, taxes, depreciation, and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations. Adjusted net debt to comparable EBITDA in 2016 improved compared to 2015 due to the lower debt balance due to repayments and the strengthening of the Canadian dollar, and higher comparable EBITDA. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2016, the Corporation continued to strengthen its financial position and reduce debt; using proceeds from the dropdown of the Canadian Assets to pay out the credit facility balance, and reducing the Corporation's dividend to $0.16 per common share on an annualized basis from $0.72 per common share.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures, and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

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

For the year ended Dec. 31, 2016 and 2015, net cash outflows, are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2016	2015	Increase (decrease)
Cash flow from operating activities	744	432	312
Change in non-cash working capital	(73)	242	(315)
Cash flow from operations before changes in working capital	671	674	(3)
Dividends paid on common shares	(69)	(124)	55
Dividends paid on preferred shares	(42)	(46)	4
Distributions paid to subsidiaries' non-controlling interests	(151)	(99)	(52)
Property, plant, and equipment expenditures(1)	(358)	(476)	118
Acquisitions	-	(101)	101
Outflow	51	(172)	223

(1) Includes growth capital associated with the South Hedland power project.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2016, $1.4 billion (2015 - $1.3 billion) of the Corporation's available credit facilities were not drawn.

Periodically, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges. TransAlta is focused on replacing additional maturing recourse debt with debt secured by contracted cash flows.

During 2016, the Corporation paid out the credit facilities balance from a combination of cash flows from operations and net cash proceeds of $173 million received from the sale of the economic interest of the Canadian assets that closed Jan. 6, 2016, (see Note 4), extended the Corporation's committed syndicated credit facility by one year to 2020, extended four bilateral credit facilities to 2018 and 2020, paid out a matured $27 million non-recourse debenture using existing liquidity, the Corporation's subsidiary New Richmond Wind L.P. issued a $159 million non-recourse bond, the Corporation's indirect wholly-owned subsidiary TAPC Holdings L.P. issued a $202.5 million non-recourse bond, and converted 1.8 million of the Series A Shares into Series B Shares. For further details see Notes 21 and 24.

During 2015, the Corporation repaid US$500 million of senior notes that matured; completed a refinancing at the Pingston facility for gross proceeds of $45 million; entered into an investment agreement to dropdown the Australian portfolio to TransAlta Renewables for gross proceeds of $217 million; and issued $442 million of senior secured amortizing debt through Melancthon Wolfe Wind LP with proceeds partially used to repay the $120 million CHD maturity.

31. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2016 are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	U.S.	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	U.S.	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	64.0	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	2016	2015	2014
Total compensation	20	9	13
Comprised of:			
Short-term employee benefits	8	8	8
Post-employment benefits	2	2	2
Termination benefits	-	1	-
Share-based payments	10	(2)	3

32. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2017	2018	2019	2020	2021	2022 and thereafter	Total
Natural gas, transportation, and other purchase contracts	40	13	6	5	5	100	**169**
Transmission	9	11	8	8	4	3	**43**
Coal supply and mining agreements	163	48	49	51	52	472	**835**
Long-term service agreements	79	29	24	41	30	51	**254**
Non-cancellable operating leases(1)	7	7	7	7	7	68	**103**
Growth	181	5	1	-	-	-	**187**
TransAlta Energy Bill	6	6	6	6	6	12	**42**
Total	**485**	**119**	**101**	**118**	**104**	**706**	**1,633**

(1) Includes amounts under certain evergreen contracts on the assumption of the Corporation's continued operations.

A. Natural Gas, Transportation, and Other Purchase Contracts

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

B. Transmission

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes and prices, with dates extending to 2025.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements. Some of these agreements and the related commitments may be impacted by the cessation of coal-fired emissions from the Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

D. Long-Term Service Agreements

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

E. Non-Cancellable Operating Leases

TransAlta has operating leases in place for buildings, vehicles, and various types of equipment and commitments for water rights and transmission tower right of ways.

During the year ended Dec. 31, 2016, $9 million (2015 - $9 million, 2014 - $10 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2016 and 2015 were less than $1 million (2015 – less than $1 million). No contingent rental payments were made in respect of these operating leases.

F. Growth

Commitments for growth primarily relate to the construction of the South Hedland power project.

G. TransAlta Energy Bill Commitments

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining 10-year life of the Centralia coal plant to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Dec. 31, 2016, the Corporation has funded approximately US$22 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation is participating in a line loss rule proceeding (the "LLRP") which is currently before the AUC. The AUC determined that it had the ability to retroactively adjust line loss rates beginning in 2006 and has directed the Alberta Electric System Operator (the "AESO"), among other actions, to perform such calculations. The various decisions by the AUC are subject to appeal and challenge. The Corporation may incur additional transmission charges as a result of the LLRP. The outcome of the LLRP remains uncertain and the potential exposure, if any, cannot be calculated with any degree of certainty until the retroactive calculations are made available. The AESO expects retroactive calculations to be available mid-2017, at the earliest. As a result, no provision has been recorded. Certain PPAs for the Corporation's Alberta facilities provide for the pass through of these types of transmission charges to the Corporation's buyers.

33. Segment Disclosures

A. Description of Reportable Segments

The Corporation has eight reportable segments as described in Note 1. During 2016, the Corporation disaggregated presentation of the previous Gas reportable segment into its two operating segments; Canadian Gas and Australian Gas. See Note 3 for further details.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	1,048	354	402	119	272	126	76	-	2,397
Fuel and purchased power	451	281	185	20	18	8	-	-	963
Gross margin	597	73	217	99	254	118	76	-	1,434
Operations, maintenance, and administration	178	54	54	25	52	33	24	69	489
Depreciation and amortization	242	61	100	17	119	33	3	26	601
Asset impairment	-	-	-	-	28	-	-	-	28
Restructuring provision	-	-	-	-	-	-	-	1	1
Taxes, other than income taxes	13	4	1	1	8	3	-	1	31
Net other operating income	(2)	-	(191)	-	(1)	-	-	-	(194)
Operating income (loss)	166	(46)	253	56	48	49	49	(97)	478
Finance lease income	-	-	14	52	-	-	-	-	66
Gain on sale of assets	-	-	-	-	-	-	-	-	4
Net interest expense									(229)
Foreign exchange loss									(5)
Earnings before income taxes									314

Year ended Dec. 31, 2015 (Restated - See Note 3)	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	372	454	114	250	116	49	-	2,267
Fuel and purchased power	441	316	204	20	19	8	-	-	1,008
Gross margin	471	56	250	94	231	108	49	-	1,259
Operations, maintenance, and administration	194	50	67	21	48	29	12	71	492
Depreciation and amortization	237	63	75	20	99	25	1	25	545
Asset impairment recovery	-	(2)	-	-	-	-	-	-	(2)
Restructuring provision	11	1	1	-	-	-	3	6	22
Taxes, other than income taxes	12	3	3	-	7	3	-	1	29
Net other operating (income) loss	(7)	-	-	-	-	(24)	56	-	25
Operating income (loss)	24	(59)	104	53	77	75	(23)	(103)	148
Finance lease income	-	-	9	49	-	-	-	-	58
Gain on sale of assets	-	-	262	-	-	-	-	-	262
Net interest expense									(251)
Foreign exchange gain									4
Earnings before income taxes									221

Year ended Dec. 31, 2014 *(Restated - see Note 3)*	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	1,023	423	573	118	247	131	108	-	2,623
Fuel and purchased power	492	255	299	23	14	9	-	-	1,092
Gross margin	531	168	274	95	233	122	108	-	1,531
Operations, maintenance, and administration	196	49	69	33	48	39	33	75	542
Depreciation and amortization	235	54	94	17	88	24	-	26	538
Asset impairment reversals	-	(5)	(1)	-	-	-	-	-	(6)
Taxes, other than income taxes	12	3	4	-	6	3	-	1	29
Net other operating (income) losses	(9)	-	-	-	-	(10)	5	-	(14)
Operating income (loss)	97	67	108	45	91	66	70	(102)	442
Finance lease income	-	-	7	42	-	-	-	-	49
Gain on sale of assets									2
Net interest expense									(254)
Earnings before income taxes									239

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2016 are $19 million (2015 - $20 million, 2014 - $21 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases, is included in revenues, and was $221 million for the year ended Dec. 31, 2016 (2014 - $230 million, 2014 - $219 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	-	-	-		175	259	30	-	464
PP&E	3,069	428	414	527	1,856	503	2	25	6,824
Intangible assets	93	7	4	12	163	3	15	58	355

As at Dec. 31, 2015	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	-	-	-	-	176	259	30	-	465
PP&E *(Restated - Note 3)*	3,148	484	512	472	2,043	486	2	26	7,173
Intangibles *(Restated - Note 3)*	92	6	2	13	176	3	17	60	369

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2016	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	159	15	11	107	16	43	-	7	358
Intangible assets	3	1	1	-	-	-	-	16	21

Year ended Dec. 31, 2015	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E *(Restated - Note 3)*	179	13	19	204	13	43	1	4	476
Intangibles *(Restated - Note 3)*	6	-	-	-	-	-	3	17	26

Year ended Dec. 31, 2014	Canadian Coal	U.S. Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E *(Restated - Note 3)*	206	14	58	148	13	42	1	5	487
Intangibles *(Restated - Note 3)*	2	-	-	7	-	-	8	17	34

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

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

Year ended Dec. 31	2016	2015	2014
Depreciation and amortization expense on the Consolidated Statements of Earnings	601	545	538
Depreciation included in fuel and purchased power *(Note 5)*	63	59	56
Loss on disposal of property, plant, and equipment	-	1	1
Depreciation and amortization on the Consolidated Statements of Cash Flows	**664**	605	595

C. Geographic Information

I. Revenues

Year ended Dec. 31	2016	2015	2014
Canada	1,828	1,705	1,989
U.S.	450	448	516
Australia	119	114	118
Total revenue	**2,397**	2,267	2,623

II. Non-Current Assets

	Property, plant, and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Canada	**5,583**	5,902	**315**	328	**184**	79	**417**	417
U.S.	**714**	799	**28**	28	**42**	37	**47**	48
Australia	**527**	472	**12**	13	**16**	17	**-**	-
Total	**6,824**	7,173	**355**	369	**242**	133	**464**	465

D. Significant Customer

During the year ended Dec. 31, 2016, sales to two customers represented 25 per cent and 16 per cent, respectively, of the Corporation's total revenue (2015 - 13 per cent and 17 per cent).

34. Subsequent Events

A. Preferred Share Exchange

On Feb. 10, 2017, the Corporation announced that it would not proceed with the transaction previously announced on Dec. 19, 2016, pursuant to which all currently outstanding first preferred shares in the capital of the Corporation would be exchanged for shares in a single new series of cumulative redeemable minimum rate reset first preferred shares in the capital of the Corporation.

B. Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale closed March 1, 2017.

Exhibit 1

(Unaudited)

The information set out below is referred to as "unaudited" as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the "Consolidated Financial Statements".

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2016:

Earnings coverage on long-term debt supporting the Corporation's Shelf Prospectus

1.85 times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	**2016**	2015	2014
Financial Summary			
Statement of Earnings			
Revenues	**2,397**	2,267	2,623
Operating income	**478**	148	442
Net earnings (loss) attributable to common shareholders	**117**	(24)	141
Statement of Financial Position			
Total assets	**10,996**	10,947	9,833
Current portion of long-term debt, net of cash and cash equivalents	**334**	33	708
Credit facilities, long-term debt, and finance lease obligations	**3,722**	4,408	3,305
Non-controlling interests	**1,152**	1,029	594
Preferred shares	**942**	942	942
Equity attributable to common shareholders	**2,569**	2,419	2,342
Fair value (asset) liability of hedging instruments on debt	**(163)**	(190)	(96)
Total invested capital(1)	**8,556**	8,641	7,795
Cash Flows			
Cash flow from operating activities	**744**	432	796
Cash flow used in investing activities	**(327)**	(573)	(292)
Common Share Information *(per share)*			
Net earnings (loss)	**0.41**	(0.09)	0.52
Comparable earnings(2)	**0.13**	(0.17)	0.25
Dividends paid on common shares	**0.30**	0.72	0.83
Book value per common share *(at year-end)*	**8.92**	8.52	8.52
Market price:			
High	**7.54**	12.34	14.94
Low	**3.76**	4.13	9.81
Close *(Toronto Stock Exchange at Dec. 31)*	**7.43**	4.91	10.52
Ratios *(percentage except where noted)*			
Adjusted net debt to invested capital	**51.0**	54.6	56.3
Adjusted net debt to invested capital excluding non-recourse debt	**44.2**	50.2	54.1
Adjusted net debt to comparable EBITDA *(times)*(2)	**3.8**	5.0	4.2
Return on equity attributable to common shareholders	**5.4**	(1.2)	6.3
Comparable return on equity attributable to common shareholders(2)	**1.7**	(2.3)	3.0
Return on capital employed	**5.3**	4.6	5.8
Comparable return on capital employed(2)	**4.4**	3.0	5.1
Earnings coverage *(times)*	**1.7**	1.5	1.7
Dividend payout ratio based on comparable funds from operations(2)	**7.8**	28.3	26.4
Comparable EBITDA *(in millions of Canadian dollars)*(2)	**1,145**	945	1,036
Dividend coverage *(times)*	**11.5**	3.6	5.7
Dividend yield	**4.0**	14.7	7.9
Adjusted comparable funds from operations to adjusted net debt	**17.0**	15.2	16.9
Comparable funds from operations before interest to adjusted interest coverage *(times)*	**3.8**	3.8	3.8
Weighted average common shares for the year *(in millions)*	**288**	280	273
Common shares outstanding at Dec. 31 *(in millions)*	**288**	284	275
Statistical Summary			
Number of employees	**2,341**	2,380	2,786
Generating capacity *(MW)*(3)			
Coal (Canadian and U.S.)	**5,131**	5,126	5,111
Gas(4)	**1,482**	1,405	1,531
Renewables (wind, solar and hydro)	**2,334**	2,350	2,204
Equity investments	**-**	-	-
Total generating capacity	**8,947**	8,881	8,846
Total generation production *(GWh)*	**38,157**	40,673	45,002

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")

	2013	2012	2011	2010	2009	2008	2007	2006
	2,292	2,210	2,618	2,673	2,770	3,110	2,775	2,677
	195	(214)	645	487	378	533	541	157
	(71)	(615)	290	255	181	235	309	45
	9,624	9,503	9,780	9,635	9,762	7,815	7,157	7,460
	175	582	284	202	(51)	194	600	296
	4,130	3,610	3,721	3,823	4,411	2,564	1,837	2,221
	517	330	358	431	478	469	496	535
	781	–	–	–	–	–	–	175
	2,125	3,018	3,274	3,120	2,929	2,510	2,299	2,428
	(16)	50	32	41	16	–	–	–
	7,712	7,590	7,669	7,617	7,783	5,737	5,232	5,655
	765	520	690	838	580	1,038	847	490
	(703)	(1,048)	(608)	(765)	(1,598)	(581)	(410)	(261)
	(0.27)	(2.62)	1.31	1.16	0.90	1.18	1.53	0.22
	0.31	0.50	1.05	0.97	0.90	1.46	1.31	1.16
	1.16	1.16	1.16	1.16	1.16	1.08	1.00	1.00
	7.92	8.78	12.08	12.85	13.41	12.70	11.39	11.99
	16.86	21.37	23.24	23.98	25.30	37.50	34.00	26.91
	12.91	14.11	19.45	19.61	18.11	21.00	23.79	20.22
	13.48	15.12	21.02	21.15	23.48	24.30	33.35	26.64
	60.7	61.0	52.5	53.1	56.1	48.1	46.8	44.5
	58.7	59.0	60.0	50.7	52.6	45.6	44.0	41.0
	4.6	4.6	3.8	–	–	–	–	–
	(3.2)	(25.9)	10.6	9.6	6.9	9.4	13.1	1.8
	3.7	4.9	8.4	8.0	6.9	11.6	10.5	9.2
	2.8	(3.1)	8.3	6.6	5.7	7.7	9.8	2.4
	5.2	5.3	7.0	6.0	5.8	9.6	9.7	9.0
	0.8	(1.0)	2.7	2.2	1.9	2.8	3.3	0.5
	43.1	25.1	24.0	39.6	–	–	–	–
	1,023	1,015	1,044	955	888	1,006	980	–
	6.3	4.7	3.5	4.0	2.6	4.8	4.2	2.4
	8.6	7.7	5.5	5.5	4.9	4.4	3.0	3.8
	15.2	16.7	20.1	19.6	20.5	31.7	30.7	26.2
	3.7	3.3	4.4	4.6	4.9	7.2	6.6	5.5
	264	235	222	219	201	199	202	201
	268	255	224	220	218	198	201	202
	2,772	2,084	2,235	2,389	2,343	2,200	2,201	2,687
	5,111	4,551	4,325	4,688	4,967	4,942	4,942	4,887
	1,779	1,731	1,567	1,648	1,843	1,913	1,960	1,953
	2,202	2,058	1,974	1,950	1,965	1,218	1,122	1,122
	396	390	390	390	–	–	–	–
	9,488	8,730	8,256	8,676	8,775	8,073	8,024	7,962
	42,482	38,750	41,012	48,614	45,736	48,891	50,395	48,213

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 Dec. 31, 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	790	25%	198	Western Canada	Alberta PPA/ Merchant[6]	2020
	Centralia, WA	1,340	100%	1,340	United States	LTC[7]/Merchant	2020-2025[8]
Total Coal		**5,990**		**4,933**			
Gas 13 Facilities	Poplar Creek, AB[9]	230	100%	230	Western Canada	LTC	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*[10][11]	245	100%	245	Australia	LTC	2023
	South Hedland, WA*[11][12]	150	100%	150	Australia	LTC	2042
	Solomon, WA*[11]	125	100%	125	Australia	LTC	2028
	Parkeston, WA*[11]	110	50%	55	Australia	LTC	2026
Total Gas		**1,738**		**1,473**			
Wind 21 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[13]	88	51%	45	Western Canada	Merchant	-
	Castle River, AB*[14]	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 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*[15]	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*[15]	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		**1,505**		**1,363**			
Solar 1 Facility	Mass Solar, MA[16]	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
	Bighorn, 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*	10	100%	10	Western Canada	LTC	2046
	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		**10,202**		**8,716**			

* *TransAlta Renewables Inc. facility.*

(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 December 31, 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) Merchant capacity refers to uprates on unit 1 (10 MW).
(7) LTC refers to Long-Term Contract.
(8) Contract is in place until 2025; however, one unit is set to retire in 2020.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) Comprised of four facilities.
(11) Gas/diesel.
(12) Plant is under construction and expected to be fully commissioned in mid-2017.
(13) On January 16, 2017 we announced the sale of our 51% interest in Wintering Hills. The transaction closed in the first quarter of 2017.
(14) Includes seven individual turbines at other locations.
(15) Comprised of two facilities.
(16) Comprised of four ground-mounted projects and four roof-top projects.

Sustainability Performance Indicators

Corporate Statistics

Environment, Health and Safety Management Systems	2016	2015	2014
Facilities with ISO 14001 and/or OHSAS 18001-based management systems *(percentage)*(1)	**97**	97	98
Management system audits(2)	**35**	23	26

Environmental Performance	2016	2015	2014
Resource or Energy Use(3)			
Coal combustion *(tonnes)* ✓	**15,735,300**	16,222,300	17,851,900
Natural gas combustion *(GJ)* ✓	**62,490,800**	63,411,200	58,273,000
Diesel combustion *(L)* ✓	**43,824,800**	22,557,000	261,400
Gasoline consumption: vehicle *(L)* ✓	**1,487,200**	1,376,300	1,474,100
Diesel consumption: vehicle *(L)* ✓	**40,226,100**	43,182,100	40,959,900
Propane consumption: vehicle *(L)* ✓	**78,800**	113,600	135,900
Electricity: building operations *(MWh)* ✓	**359,300**	220,800	244,800
Natural gas: building operations *(GJ)* ✓	**58,300**	58,500	72,400
Propane: building operations *(L)* ✓	**127,500**	102,700	63,600
Kerosene: building operations *(L)* ✓	**56,500**	60,100	54,800
Total resource or energy use *(GJ)* ✓	**528,353,700**	542,362,600	584,070,500
Greenhouse Gas Emissions(4)			
Carbon dioxide *(tonnes CO_2e)* ✓	**30,375,900**	31,902,700	34,724,400
Methane *(tonnes CO_2e)* ✓	**114,200**	112,600	119,200
Nitrous oxide *(tonnes CO_2e)* ✓	**224,500**	212,400	231,200
Sulphur hexafluoride *(tonnes CO_2e)*	**20**	20	10
Total greenhouse gas emissions *(tonnes CO_2e)*(5) ✓	**30,714,600**	32,227,800	35,074,800
Greenhouse gas emission intensity *(tonnes CO_2e/MWh)*(6) ✓	**0.84**	0.87	0.88
Air Emissions(7)			
Total sulphur dioxide emissions *(tonnes)* ✓	**39,600**	41,800	47,600
Sulphur dioxide emission intensity *(kg/MWh)*(8) ✓	**1.09**	1.13	1.2
Total nitrogen oxide emissions *(tonnes)* ✓	**48,400**	48,000	52,900
Nitrogen oxide emission intensity *(kg/MWh)*(8) ✓	**1.33**	1.30	1.34
Total particulate matter emissions *(tonnes)* ✓	**4,900**	4,900	5,200
Particulate matter emission intensity *(kg/MWh)*(8) ✓	**0.14**	0.13	0.13
Total mercury emissions *(kilograms)* ✓	**130**	170	220
Mercury emission intensity *(mg/MWh)*(8) ✓	**3.54**	4.50	5.66
Water Management(9)			
Water intake *(million m^3)* ✓	**247**	272	243
Water discharge *(million m^3)* ✓	**188**	198	172
Water consumption *(million m^3)* ✓	**59**	74	71
Water intensity *(m^3/MWh)*(10) ✓	**2**	2	2
Waste Management(11)			
Non-Hazardous			
Landfill *(tonnes)* ✓	**2,100**	2,400	2,500
Landfill *(L)* ✓	**518,400**	131,200	42,300
Ash disposal: mine *(tonnes)*(12) ✓	**1,315,000**	1,346,900	1,636,200
Ash disposal: lagoon *(tonnes)*(13) ✓	**527,700**	501,600	532,800
Recycled *(tonnes)* ✓	**18,000**	151,100	89,000
Recycled *(L)* ✓	**212,100**	222,100	157,500
Reuse *(tonnes)* ✓	**700,700**	707,800	846,300
Storage *(tonnes)* ✓	**8,300**	14,800	33,600

Environmental Performance *(continued)*	**2016**	**2015**	**2014**
Waste Management *(continued)*			
Hazardous[14]			
Landfill *(tonnes)* ✓	**40**	40	10
Landfill *(L)* ✓	**13,100**	3,300	569,100
Recycled *(tonnes)* ✓	**60**	80	50
Recycled *(L)* ✓	**17,209,600**	536,100	352,400
Land Use and Reclamation[15]			
Land used in mining activities: disturbed *(cumulative hectares)*	**11,800**	11,700	11,600
Land used in mining activities: reclaimed *(cumulative hectares)*	**4,600**	4,500	4,500
Land reclamation *(% of land disturbed)*[16]	**39**	39	39
Land used in mining activities: disturbed minus reclaimed *(hectares)*	**7,200**	7,200	7,100
Land used by plants, offices, and equipment *(hectares)*	**3,900**	3,900	3,700
Total land use *(cumulative hectares)*	**11,100**	11,100	10,900
Environmental Incidents			
Total environmental incidents[17] ✓	**16**	12	15
Environmental enforcement actions	**0**	1	0
Environmental fines *($ thousands)*	**0**	2	0
Spills[18]			
Volume of significant spills *(m^3)*	**61**	19	463
Volume of significant spills recovered *(m^3)*	**47**	19	446
% of spills recovered	**78**	99	96

Social Performance	**2016**	**2015**	**2014**
Workplace Practices			
Employees	**2,341**	2,380	2,786
Number of full-time employees	**2,267**	2,301	2,629
Number of part-time employees	**26**	26	79
Number of contingent employees	**48**	53	78
Employees represented by independent trade union organizations *(%)*[19]	**53**	54	53
Voluntary employee turnover rate *(%)*[20]	**6.71**	5.22	6.97
Diversity			
Women in workforce *(%)*	**18**	18	19
Women in senior management *(%)*	**26**	25	35
Women on Board of Directors *(%)*	**33**	30	36
Health and Safety			
Health and safety enforcement actions[21]	**4**	0	0
Health and safety fines *($ thousands)*	**5**	0	0
Employee & contractor fatalities ✓	**0**	0	0
Lost-time injury (absence from work) ✓	**4**	5	5
Medical aids (no absence from work) ✓	**20**	20	17
Total injuries to employees & contractors ✓	**24**	25	22
Total injury frequency rate (employees and contractors)[22] ✓	**0.85**	0.75	0.86
Reportable vehicle incidents	**33**	28	37
Community Relations			
Community investments *($ millions)*[23]	**2.5**	3.5	3.6

✓ *2016 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, regulatory frameworks, and against the Alberta Certificate of Recognition standard.

(3) Energy use is calculated and reported from TransAlta-operated facilities following the same approach we use for greenhouse gas reporting, which is application of an Operational Control boundary.

(4) Greenhouse gas emissions (GHG) are calculated and reported from TransAlta-operated facilities in line with carbon regulation where the facility is located and with The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (specifically 'Setting Organizational Boundaries: Operational Control' methodology). As per the Operational Control methodology, TransAlta reports 100 per cent of GHG emissions from facilities at which we are the operator. GHG emissions include emissions from stationary combustion, transportation use, building use, and fugitive emissions.

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

(6) GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.

(7) Air emissions are reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is application of an Operational Control boundary. Air emissions are expressed in tonnes, except for mercury emissions, which are represented in kilograms. Particulate matter emissions include both PM2.5 and PM10.

(8) Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.

(9) Water usage is reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is application of an Operational Control boundary. Total water consumed is measured by total water intake minus water discharge. Water is used primarily for cooling by our thermal power plants. Evaporative losses from the cooling ponds and cooling towers account for 95 per cent of the consumptive loss. The water lost to evaporation is not returned directly to the water body, but the water remains in the hydrologic cycle.

(10) Water usage intensity is calculated by dividing total operational water consumption (m^3) by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.

(11) Non-hazardous waste includes, but is not limited to, water treatment chemicals, coal refuse (including ash-byproducts), metals, paper, cardboard and building materials.

(12) Ash disposal: mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal.

(13) Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.

(14) Hazardous wastes are substances going for disposal, which – either in the short or the long term – can be harmful to people, plants, animals, or the environment.

(15) Total land use is mining land use plus land used by plants, offices, and equipment.

(16) Disturbed land use and reclaimed volumes were restated in 2016 for 2014-2016, due to an internal reconciliation reporting error.

(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.

(19) TransAlta has over 1,200 unionized workers working primarily at our operations.

(20) Voluntary turnover is aligned with our Human Resources voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any full-time, part-time, or contingent employee initiated exit, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover.

(21) Health and safety incidents are those 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. In 2016 we had four traffic enforcement actions that resulted in fines of C$5,000.

(22) 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.

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

Independent Sustainability Assurance Statement

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

Scope of Ernst & Young LLP (“EY”) Engagement

EY responsibilities included providing limited assurance over a selection of performance indicators.

Subject Matter

We have performed limited assurance procedures for the following quantitative performance indicators (“Subject Matter”) for the year ending December 31, 2016.

- 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)
- Gross greenhouse gas emissions and emissions intensity (tonnes CO_2e, tonnes CO_2e/GWh)
- Total environmental incidents
- Lost time incident 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 fatalities
- Energy use: Coal combustion (tonnes)
- Energy use: Natural gas combustion (GJ)
- Energy use: Diesel combustion (L)
- Energy use: Gasoline combustion: vehicle (L)
- Energy use: Diesel combustion: vehicle (L)
- Energy use: Propane combustion: vehicle (L)
- Energy use: Electricity – building operations (MWh)
- Energy use: Natural gas – building operations (GJ)
- Energy use: Propane – building operations (L)
- Energy use: Kerosene – building operations (L)
- Water intake, discharge, consumption (million m^3)
- Water intensity (m^3/MWh)
- Waste Management – Non-hazardous
  - Landfill (tonnes, L)
  - Ash Disposal: mine, lagoon (tonnes)
  - Recycled (tonnes, L)
  - Reuse (tonnes)
  - Storage (tonnes)
- Waste Management – Hazardous
  - Landfill (tonnes, L)
  - Recycled (tonnes, L)

Criteria

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

TransAlta Management Responsibilities

The Subject Matter was prepared by the management of TransAlta, who is responsible for the assertions, statements, and claims made therein including the assertions we have been engaged to provide limited assurance over, collection, quantification and presentation of the performance indicators and the criteria used in determining that the information is appropriate for the purpose of disclosure in this Report (“the Report”). In addition, management is responsible for maintaining adequate records and internal controls that are designed to support the reporting process.

EY Responsibilities

Our limited assurance procedures have 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".

Our procedures were designed to obtain a limited level of assurance on which to base our conclusion. 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 reasonable level of assurance. While we considered the effectiveness of management's internal controls when determining the nature and extent of our procedures, our assurance engagement was not designed to provide assurance on internal controls and, accordingly, we express no conclusions thereon.

This assurance statement has been prepared for TransAlta for the purpose of assisting management in determining whether the Subject Matter is in accordance with the criteria and for no other purpose. Our assurance statement is made solely to TransAlta in accordance with the terms of our engagement. We do not accept or assume responsibility to anyone other than TransAlta for our work, or for the conclusions we have reached in this assurance statement.

Assurance Procedures

We planned and performed our work to obtain all the evidence, information and explanations considered necessary in relation to the above scope. Our assurance procedures included but were not limited to:

- Interviewing relevant personnel at the head office and at various sites to understand data management processes related to the selected performance indicators.
- Checking the accuracy of calculations performed – on a test basis – primarily through inquiry, variance analysis and performance of re-calculations.
- Assessing risk of material misstatement due to fraud or errors relating to the selected performance indicators.
- Evaluating the overall presentation of the Report, including the consistency of the Subject Matter.

Limitations of EY 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.
- Management's forward looking statements.
- Any comparisons made by TransAlta against historical data.
- The appropriateness of definitions for internally developed criteria.

Independence and Competency Statement

In conducting our engagement, we have complied with the applicable requirements of the Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants ("IESBA").

EY Conclusion

Based on our procedures for this limited assurance engagement described in this statement, 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

March 2, 2017

Shareholder Information

Annual Meeting

The Annual Meeting of Shareholders will be held at 10:00 a.m. MST, on Thursday, April 20, 2017 at BMO Centre (Stampede Park) 20 Roundup Way SW, Calgary, Alberta.

Transfer Agent

CST Trust Company*
P.O. Box 700 Station "B"
Montreal, Quebec H3B 3K3

Phone
North America:
1.800.387.0825 toll-free
Toronto/outside North America:
416.682.3860

E-mail
inquiries@canstockta.com

Fax
514.985.8843

Website
www.canstockta.com

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.E, 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 2016

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2016	March 1, 2016	Feb. 26, 2016	$0.04
July 1, 2016	June 1, 2016	May 30, 2016	$0.04
Oct. 1, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.04
Jan. 1, 2017	Dec. 1, 2016	Nov. 29, 2016	$0.04
April 1, 2017	March 1, 2017	Feb. 27, 2017	$0.04

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 $0.67724 per share from and including March 31, 2016 to but excluding March 31, 2021.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2016 to but excluding March 31, 2021.

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 2016

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2016	March 1, 2016	Feb. 26, 2016	$0.2875
June 30, 2016	June 1, 2016	May 30, 2016	$0.16931
Sept. 30, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.16931
Dec. 31, 2016	Dec. 1, 2016	Nov. 29, 2016	$0.16931
March 31, 2017	March 1, 2017	Feb. 27, 2017	$0.16931

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2016	June 1, 2016	May 30, 2016	$0.15490
Sept. 30, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.16144
Dec. 31, 2016	Dec. 1, 2016	Nov. 29, 2016	$0.15974
March 31, 2017	March 1, 2017	Feb. 27, 2017	$0.15651

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2016	March 1, 2016	Feb. 26, 2016	$0.2875
June 30, 2016	June 1, 2016	May 30, 2016	$0.2875
Sept. 30, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.2875
Dec. 31, 2016	Dec. 1, 2016	Nov. 29, 2016	$0.2875
March 31, 2017	March 1, 2017	Feb. 27, 2017	$0.2875

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2016	March 1, 2016	Feb. 26, 2016	$0.3125
June 30, 2016	June 1, 2016	May 30, 2016	$0.3125
Sept. 30, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.3125
Dec. 31, 2016	Dec. 1, 2016	Nov. 29, 2016	$0.3125
March 31, 2017	March 1, 2017	Feb. 27, 2017	$0.3125

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2016	March 1, 2016	Feb. 26, 2016	$0.33125
June 30, 2016	June 1, 2016	May 30, 2016	$0.33125
Sept. 30, 2016	Sept. 1, 2016	Aug. 30, 2016	$0.33125
Dec. 31, 2016	Dec. 1, 2016	Nov. 29, 2016	$0.33125
March 31, 2017	March 1, 2017	Feb. 27, 2017	$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
TransAlta Corporation
110 - 12th Avenue SW
P.O. Box 1900, Station "M"
Calgary, Alberta T2P 2M1

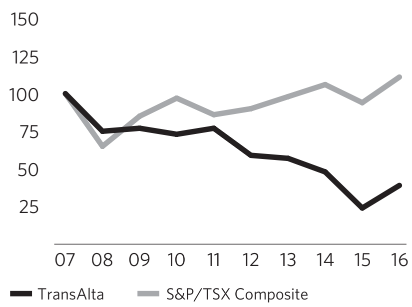
Phone
North America:
1.800.387.3598 toll-free
Calgary/outside North America:
403.267.2520

E-mail
investor_relations@transalta.com

Fax
403.267.7405

Website
www.transalta.com

Shareholder Highlights



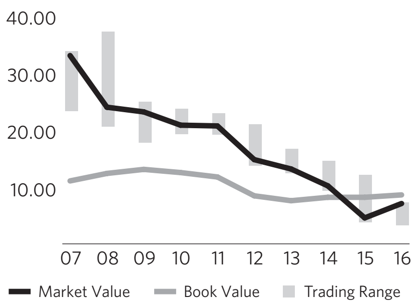
Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*

	07	08	09	10	11	12	13	14	15	16
TransAlta	100	75	77	73	77	59	57	48	24	39
S&P/TSX Composite	100	65	85	97	86	90	98	106	94	111

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite at the end of 2007 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet



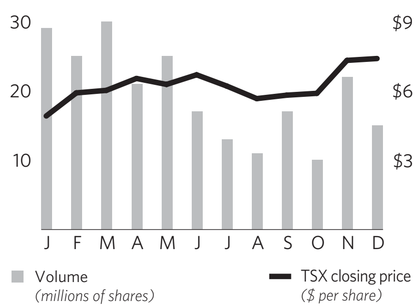
Ten-Year Trading Range and Market Value vs. Book Value

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

	07	08	09	10	11	12	13	14	15	16
Market Value	33.35	24.30	23.48	21.15	21.02	15.12	13.48	10.52	4.91	7.43
Book Value	11.39	12.70	13.41	12.85	12.08	8.78	7.92	8.52	8.52	8.92

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: FactSet and TransAlta

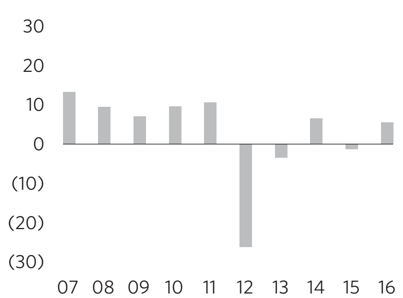


Monthly Volume and Market Prices

(2016)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	29	25	30	21	25	17	13	11	17	10	22	15
TSX closing price	4.92	5.93	6.04	6.56	6.30	6.72	6.23	5.68	5.83	5.91	7.35	7.43

Source: FactSet



Return on Common Shareholders' Equity

(%)

	07	08	09	10	11	12	13	14	15	16
ROE	13.1	9.4	6.9	9.6	10.6	(25.9)	(3.2)	6.3	(1.2)	5.4

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 Chairs, 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**
Email: **TA_ethics_helpline@transalta.com**

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

TransAlta Corporate Officers

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Todd J. Stack
Managing Director, Corporate Controller

Scott T. 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.

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 assets 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.

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.

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