TransAlta™

Power

Low Cost
Reliable
Clean
Firm

TransAlta Corporation

2017 Annual Integrated Report

Letter to Shareholders

Dear Fellow Shareholders,

At TransAlta we make the energy our customers need and want. For over 100 years we have produced reliable power. Today, the demand for low-cost and reliable energy is greater than ever — and it must be clean and available at the flip of a switch, 24/7.

Renewable power sources alone cannot provide this guarantee. TransAlta's asset mix can. With a mix of hydro, wind, gas and solar power, TransAlta has the assets, expertise and growth platform to help meet the demand for clean power, while not compromising on reliability.

By 2025 we will deliver 100 per cent clean power and be the energy provider of choice.
To achieve this, we are accelerating the conversion of our coal plants to natural gas, strengthening our balance sheet and advancing our growth projects. We will combine natural gas with renewable power to deliver the reliability the market demands. As I outline in this letter, we have already made significant headway and a future of clean energy leadership is well within our grasp.

2015-2017: Building the Framework for Success
Over the course of two short years we eliminated the uncertainty surrounding TransAlta's future in a clean energy environment and established the framework for future operating success.

We preserved maximum value from our coal plants by securing an additional 75 years of combined life for our existing coal facilities and adding more than $1 billion in anticipated free cash flow and $37 million annual off-coal payments from the province of Alberta.

We negotiated full credit for our renewable assets under the carbon credit regime. As a result, over time, our wind and hydropower assets in Alberta will deliver $30 million to $50 million in value annually.

We supported the development of a capacity market in Alberta, which we expect will allow us to bid our converted gas plants to support our customers.

We strengthened our balance sheet — reducing net debt by $500 million, increasing our financial flexibility and preserving our investment grade credit rating.

> Everything we do in 2018 and beyond will move us closer to 100 per cent clean power by 2025.

These significant achievements, over the past two years, give us the clarity and confidence we need to execute informed plans that propel us forward to a future of 100 per cent clean electricity. Our 2017 financial performance also demonstrates the strength of the underlying fundamentals of our business. In terms of overall performance, in 2017, we generated more cash flow than we have ever generated, at $328 million, and we gained significant confidence in future cash flows through the execution of our strategic efficiency initiative, and our decision to transition to gas-fired generation.

2018-2020: Becoming the Energy Provider of Choice

Customers want power that helps make them competitive, environmentally sensitive, forward-looking and proud of who provides their power. We can offer this. To do so, we must enhance our balance sheet to preserve our investment grade credit rating — the assurance that major industrial and commercial customers require to do business with us.

We are in the final innings of our debt repayment program. Between 2018 and 2020, we will reduce our senior corporate debt to $1.1 billion, and have $1.0 billion of amortizing project debt secured by our contracted portfolio. We believe this is an appropriate amount of leverage for our Alberta coal and hydro assets. By 2020, our FFO/debt ratio will give us a balance sheet that can weather any storm. It also means that capital allocation from here can start to focus on returns to shareholders and new growth. We know that customers value a strong balance sheet and it's a key competitive advantage in our business.

We are re-tooling our business to sharpen our focus on the customer and to enable our employees to get work done! Our internal efficiency initiative, Project Greenlight, is driving millions of dollars in cash value from more efficient processes that will equip us to serve more customers, better. We are already benefiting from leaner, more efficient operations with plenty of scope to generate additional recurring savings. What I love about Greenlight is that it involves and rewards our people from the front lines to the back lines in over 900 initiatives are improving the company in every corner of our operations. It is a new tool for the future and it's a game-changer for our culture.

2025: Generating 100 Per Cent Clean Power

Everything we do in 2018 and beyond will move us closer to 100 per cent clean power by 2025. Our teams are motivated and focused around this common goal. We are moving ahead with our plans to transition from coal to gas. We will continue to strategically manage our operational flexibility to ensure efficient capital allocation and energy supply based on market demands.

At the end of 2017, we had to take the unusual step of consolidating our operations at Sundance to improve efficiency by reducing coal and greenhouse gas emissions. With carbon now priced in Alberta, we simply must optimize around carbon costs.

In the new capacity market, we will have the opportunity to return five Sundance units to service as we transition them to gas-fired generation. Our Sundance and Keephills units are part of our vision for clean power by 2025. When the wind isn't blowing, the water isn't flowing, and the sun isn't shining, we'll be supporting customers in Alberta out of these plants.

> “As we think about a cleaner 2025, we are very clear that renewables play a much larger part.

To meet the competitive pressures in Alberta, we’ve set a goal to have all our coal plants converted to gas by 2022. To ensure success, we have secured a pipeline agreement that will connect our plants to gas supply. This means we can begin to blend our coal with gas to reduce costs, emissions and carbon tax expenses and crucially get to work on our coal-to-gas conversions a year earlier than expected.

As we think about a cleaner 2025, we are very clear that renewables play a much larger part. Therefore, we are continuing to invest in the exploratory development of our Brazeau Hydro pumped storage expansion plan, which will meet the demand for clean, low cost, reliable and firm power. A project like Brazeau will require a policy environment that supports the vision that clean, carbon-free power will dominate in Canada. We look forward to large hydro being a key part of the mix for Alberta again. By pushing on projects like Brazeau today, we can take Alberta to a future where power is low cost — **green** — firm and reliable.

Capital Allocation

We have a clear line of sight to $1.2 billion in free cash flow from our existing operations between 2018 and 2020 — $1 billion coming from our ongoing operations and $200 million coming from the PPA termination of the Sundance units. This cash backs up our financial plan and positions us for strong capital allocation decisions going forward, including the share buyback as described in Chairman Giffin’s Letter to Shareholders.

Today, TransAlta is focused on converting our coal plants to gas and maximizing the value of our hydro assets. TransAlta Renewables is focused on growing contracted cash flows from wind, solar, hydro and storage for customers both inside and outside of Alberta. The great news is that we are returning to a time when TransAlta can take our cash from our Alberta assets and our contracted renewables assets and think carefully about capital allocation.

On behalf of our leadership team, we very much appreciate all your support and we thank our people for all that they do every day to serve our customers and build our company.

Dawn L. Farrell
President and Chief Executive Officer

March 1, 2018

Message from the Chair

From your Board's perspective, 2017 can be best characterized in one word — progress. Steady, strategic progress.

First, let me assure you that the Board listened to the message delivered by our shareholders through the say-on-pay vote last spring. The Board and management are firmly committed to a compensation philosophy with the principle of pay for performance at its core. We have undertaken an extensive outreach program, creating an ongoing dialogue with shareholders so that we remain current on your thinking. We have also enhanced our approach to executive compensation, which is described in more detail in the Compensation Discussion & Analysis.

Much like the legendary tortoise, without a lot of flash or attention, your TransAlta employee team, across the company, made substantial progress to improve the company's performance and to position it for success in the new and evolving power sector of the future.

In early 2017, TransAlta stated its strategic mission to become Canada's leading clean power company, thereby creating value for its shareholders, customers, employees and other stakeholders in the decades ahead. In pursuit of that vision, 2017 saw many achievements, among them greater efficiency and innovation, debt reduction and an accelerated plan to convert our coal plants to gas. These are described in greater detail in President and CEO Dawn Farrell's accompanying letter.

With the better-than-expected performance from the business, and the strong outlook, we are confident in the execution of our plan for 2018 to 2020 and have decided to allocate a portion of our capital to buy back our shares when we feel they are undervalued. In 2019, as the business continues to thrive, our de-leveraging program will be complete and we'll start to have more significant discussions about capital allocation.

While the public markets have yet to recognize TransAlta's progress, the Board believes the financial performance of the company has improved and our strategy is strong. The market will catch up to the decisions we have made.

As always, the Board and management are focused on the future. There are new opportunities ahead, including the transition to a capacity market and what is proving to be a very competitive environment in which to build the next generation of renewables. TransAlta is ready. The Board would like to express its ongoing confidence in TransAlta's leadership team and their vision. We value and appreciate their determination and personal resolve.

In summary, the Board and the dedicated team of TransAlta employees have been diligent in the rigorous pursuit of actions and policies to make TransAlta the leading clean power generator — a company that consistently delivers value to shareholders. This is a marathon, not a sprint, and the Board is confident that our management has its eyes on the finish line, and, like that tortoise, is on an inexorable path to cross it.

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chair of the Board of Directors

March 1, 2018

Management's Discussion and Analysis

Table of Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2017 consolidated financial statements and our Annual Information Form for the year ended Dec. 31, 2017. 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, 2017. 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 1, 2018. 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 or our social media channels 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 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 model 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 the Brazeau Hydro pumped storage Project, the Kent Hills 3 Wind Project, the Antelope Coulee Wind Project, the Garden Plain wind Project, and the conversion of our Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation, and their timing, attendant costs and sources of funding; the benefits to be realized from converting coal-fired facilities to gas-fired facilities, including reductions in emissions; the retirement of Sundance Unit 1 and the mothballing of Sundance Units 2 to 5; the compensation expected from the Balancing Pool and sustaining capital expenditures in connection with the termination of the Alberta Power Purchase Arrangements; 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 section titled "2018 Financial Outlook"; the ability of Sundance Unit 2 to qualify for the expected 2019 capacity market auction; coal supply constraints for our facilities in Alberta and their impact on our mining costs and power generation at our Sundance Units 3 to 6 and Keephills Units 1 to 3; the impact of certain hedges on future reported earnings and cash flows, including future reversals of unrealized gains or losses; our dividend payout ratio; expectations related to future earnings and cash flow from operating and contracting activities (including estimates of full-year 2018 comparable earnings before interest, depreciation and amortization ("EBITDA"), funds from operations ("FFO") and 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 FFO before interest to adjusted interest coverage, adjusted FFO to adjusted net debt, and adjusted net debt to comparable EBITDA); Canadian Coal Fleet availability; the anticipated financial impact to be realized from the commercial operation of the South Hedland Power Station; our ability to establish that all conditions to commercial operation of our South Hedland Power Station have been satisfied with Fortescue Metals Group Limited ("FMG"); the Corporation's plans and strategies relating to repositioning its capital structure and strengthening its balance sheet and the anticipated debt reductions; the terms of the anticipated normal course issuer bid ("NCIB"), including the timing, number of shares to be repurchased pursuant to the NCIB, and the acceptance thereof by the Toronto Stock Exchange; expected governmental regulatory regimes and legislation, including the federal carbon price, the Government of Alberta's intended shift to a capacity market and renewable auctions and the expected impacts on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; the expected results and impact of the Off-Coal Agreement ("OCA") with the Government of Alberta on our business and financial performance; estimates of fuel supply and demand conditions and the costs of procuring fuel; the impact of load growth, increased capacity, and natural gas costs on power prices; expectations in respect of generation availability, capacity, and production; power prices in Alberta, Ontario, and the Pacific Northwest; expected financing of our capital expenditures; the anticipated financial impact of increased carbon prices, including under the Carbon Competitiveness Incentive Regulation ("CCIR") in Alberta; expectations in respect of our environmental initiatives including reductions to our emissions, environmental incidents, and energy use, including the reduction in greenhouse gas ("GHG") emissions of 60 per cent or 12 million tonnes CO_2e; nitrogen dioxide emissions being reduced 50 per cent; 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 on 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; our exposure to liquidity risk; expectations in respect of the global economic environment and growing scrutiny by investors relating to sustainability performance; our credit practices; expected cost savings and payback periods following the implementation of Project Greenlight and productivity initiatives, including translating certain costs from our corporate transformation into significant long-term cost savings; 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 of our upcoming debt maturities over the next two years; expectations regarding our de-leveraging strategy; expectations in respect of our community initiatives; impacts of future IFRS standards and the timing of the implementation of such 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 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; ability to compete effectively in the anticipated Alberta capacity market; changes in general economic conditions, including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; accelerated growth, whether through acquisition or greenfield development; unanticipated operating conditions; disruptions in the transmission and distribution of electricity; the effects of weather; disruptions in the source of fuels, water, sun, or wind required to operate our facilities; natural or man-made disasters; physical risks related to climate change; 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 and on reasonable terms; 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; outcomes of legal, regulatory, and contractual proceedings involving the Corporation including those with FMG at South Hedland; outcomes of investigations and disputes; reliance on key personnel; labour relations matters; risks associated with development projects and acquisitions, including delays or changes in costs in the construction and commissioning of the Kent Hills 3 wind project; and the maintenance or adoption of enabling regulatory frameworks or the satisfactory receipt of applicable regulatory approvals for existing and proposed operations and growth initiatives, including as it pertains to coal-to-gas conversions.

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 2018 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, 2017, 2016, and 2015. 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. Comparable EBITDA, FFO, comparable FFO, FCF, and cash flow generated by the business are non-IFRS measures that are presented in this MD&A. See the Reconciliation of Non-IFRS Measures and Discussion of Segmented Comparable Results 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 107 years of operating experience. As at March 1, 2018, we own, operate, and manage a highly contracted and geographically diversified portfolio of assets representing over 8,400 megawatts ("MW")(1) of gross generating capacity and use a broad range of generation fuels including coal, natural gas, water, solar, and wind. Our energy marketing team adds value by optimizing assets as market conditions change and by supplying products for customers.

Vision and Values

Our vision is to supply low cost, clean, reliable and firm electricity to our markets and customers. 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

We deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share, while striving for a low to moderate risk profile over the long term. Over the next 12 months we will continue to deleverage our balance sheet and ensure financial flexibility as we transition our coal-fired plants to gas-fired plants and move into a capacity market in Alberta. Now that our cash flows have strengthened, we can allocate capital to growth, dividends and share re-purchases.

Material Sustainability Impacts

Sustainability means ensuring that our financial returns consider short- and long-term economics, environmental impacts and societal and community needs. We track the performance of 74 sustainability-related Key Performance Indicators ("KPIs"). We obtained a limited assurance report from Ernst & Young LLP over material KPIs. Our MD&A integrates our financial and sustainability reporting.

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(1) We measure capacity as net maximum capacity (see Glossary of Key Terms for a 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	**2017**	2016	2015
Revenues	**2,307**	2,397	2,267
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Cash flow from operating activities	**626**	744	432
Comparable EBITDA[1,2]	**1,062**	1,144	867
FFO[1,2]	**804**	734	699
FCF[1,2]	**328**	257	239
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.66)**	0.41	(0.09)
FFO per share[1,2]	**2.79**	2.55	2.50
FCF per share[1,2]	**1.14**	0.89	0.85
Dividends declared per common share	**0.12**	0.20	0.72

As at Dec. 31	**2017**	2016	2015
Total assets	**10,304**	10,996	10,947
Total consolidated net debt[3]	**3,363**	3,893	4,251
Total long-term liabilities	**4,311**	5,116	5,704

2017 was a successful year for TransAlta. FCF totalled $328 million, up $72 million compared to last year. FFO was $804 million for 2017, compared to $734 million for 2016, an increase of $70 million, as most of our operations delivered year-over-year improvement in performance.

At the end of the year our total net debt was approximately $3.4 billion, down more than $500 million from the beginning of the year, due to the scheduled repayment of the US$400 million US Senior Note using existing liquidity. Our adjusted FFO to adjusted net debt and adjusted net debt to comparable EBITDA metrics improved significantly to 20.4 per cent and 3.6 times, respectively. Liquidity available at the end of the year remains at a similar level compared to last year following the payment received in November from FMG for the sale of the Solomon Power Station.

Net loss attributable to common shareholders in 2017 was $190 million ($0.66 net loss per share) compared to net earnings of $117 million ($0.41 net earnings per share) in 2016, a reduction of more than $300 million. Earnings in 2017 were negatively impacted by lower comparable EBITDA of $82 million, as well as the reduction of the US tax rate announced in December ($105 million). The US tax rate reduction was offset by an increase in other comprehensive income. Higher depreciation of $34 million year-over-year was due mostly to the shortening of the useful lives of Keephills 3 and Genesee 3 and to the commissioning of South Hedland in July. Net earnings in 2016 were positively impacted by a $48 million (net of related income tax expense and non-controlling interest) positive impact in connection with the Mississauga recontracting and the pre-tax $94 million Keephlils Unit 1 provision reversal, of which $80 million impacted comparable EBITDA.

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(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 Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) During the fourth quarter of 2017, we revised our approach to reporting adjustments to arrive at FFO, mainly to better represent FFO as a cash metric. Previously, FFO was adjusted to include, exclude, or to modify the timing of cash impacts related to adjustments made in arriving at comparable EBITDA. As a result, comparable EBITDA, FFO, and FCF for 2016 and 2015 have been revised accordingly.

(3) Total consolidated net debt includes long-term debt including current portion, amounts due under credit facilities, tax equity, and finance lease obligations, net of available cash and the fair value of economic hedging instruments on debt. See the table in the Capital Structure section of this MD&A for more details on the composition of net debt.

Segmented Cash Flow Generated by the Business[1]

Year ended Dec. 31	2017	2016	2015
Segmented cash inflow (outflow)			
Canadian Coal	175	198	177
US Coal	33	21	41
Canadian Gas	221	235	194
Australian Gas	127	99	114
Wind and Solar	201	180	163
Hydro	61	53	38
Generation cash inflow	818	786	727
Energy Marketing	39	25	17
Corporate	(108)	(95)	(102)
Total comparable cash inflow	749	716	642

Segmented cash flows generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs, and provisions. It also excludes non-cash mark-to-market gains or losses. This is the annual cash flows available to pay our interest and cash taxes, distributions to our non-controlling partners and dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders. Cash flow generated by the business totalled $749 million in 2017, up $33 million over 2016 and $74 million over 2015 in a low price environment in most markets in North America. We achieved this through a prudent contracting approach, disciplined cost control and sustaining capital expenditure allocation.

Significant Events

Our strategic focus continues to be strengthening our balance sheet, improving our operating performance, and progressing our transition to clean power generation. We made the following progress throughout the year:

- On March 1, 2018, we announced our intention to seek Toronto Stock Exchange acceptance of a normal course issuer bid ("NCIB"). See the Significant and Subsequent Events section of this MD&A for further details.
- In April 2017, we announced our plan to transition to gas and renewables generation with the retirement of Sundance Unit 1 and the mothballing of Sundance Unit 2 at the end of 2017, as well as the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation between 2021 and 2022. Subsequent to the September 2017 Balancing Pool's announcement of the termination of the PPAs in respect of Sundance B and C, we announced the acceleration of the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation in the 2021 to 2022 timeframe, a year earlier than originally planned. As a result of the termination of Sundance B and C PPAs, we determined to mothball additional capacity starting in April 2018. The coal-fired plants operated by us, once converted to gas, are anticipated to be able to run through to 2031 to 2039, which significantly lengthens their asset lives. See the Significant and Subsequent Events section of this MD&A for further details.
- During the fourth quarter, we entered into a Letter of Intent to construct a 120-kilometre natural gas pipeline to our generating units at Sundance and Keephills, to facilitate our strategy of converting our coal units to natural gas units. See the Significant and Subsequent Events section of this MD&A for further details.
- During the third quarter, we achieved commercial operation on our South Hedland Power Station. During the fourth quarter, we received formal notice of termination of the South Hedland PPA from a subsidiary of Fortescue Metals Group Limited ("FMG"), on the basis that the South Hedland Power Station had yet to achieve commercial operation. We remain confident that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the PPA. The project is expected to generate approximately $80 million of comparable EBITDA annually. TransAlta Renewables converted the Class B shares we owned into common shares and also increased its monthly dividend by approximately seven per cent. See the Significant and Subsequent Events section of this MD&A for further details.

(1) This item is 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 Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

- In November, FMG repurchased the Solomon Power Station. We received approximately US$325 million. See the Significant and Subsequent Events section of this MD&A for further details.
- During the second quarter, we entered into a long-term contract for the 17.25 MW Kent Hills 3 expansion project located in New Brunswick, which is expected to begin the construction phase in the spring of 2018.
- In May, we repaid $US400 million of senior debt using existing liquidity.
- During the third quarter, TransAlta Renewables' indirect majority-owned subsidiary, Kent Hills Wind LP, closed a $260 million project-level financing. The bonds are amortizing and bear interest at an annual rate of 4.454 per cent, payable quarterly and maturing Nov. 30, 2033. The proceeds from the financing were used to early repay maturing debt and will fund the expansion of the project. In early 2018, we announced our intention to early repay $US500 million of Senior Notes. See the Significant and Subsequent Events section of this MD&A for further details.
- During the third quarter, TransAlta Renewables entered into a syndicated credit agreement giving it access to $500 million in direct borrowings. We reduced our syndicated credit facility by the same amount. Our consolidated liquidity remains unchanged. Both facilities expire in 2021.
- In March 2017, we closed the sale of our 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million. The sale reduced our merchant exposure in Alberta and the proceeds were used to repay debt.
- During the second quarter, we settled the contract indexation dispute with the Ontario Electricity Financial Corporation ("OEFC"). The settlement consisted of a $34 million payment by the OEFC to TransAlta.

Discussion of Consolidated Financial Results

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company. Each business segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Comparable EBITDA

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. In addition, we reclassify certain transactions to facilitate the discussion on the performance of our business:

(i) Certain assets we own in Canada and Australia are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables. We depreciate these assets over their expected lives;

(ii) We also reclassify the depreciation on our mining equipment from fuel and purchased power to reflect the actual cash cost of our business in our comparable EBITDA;

(iii) In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator ("IESO") relating to our Mississauga cogeneration facility in Ontario and entered into a new Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") effective Jan. 1, 2017. Under the new NUG Contract, we receive fixed monthly payments until December 31, 2018 with no delivery obligations. Under IFRS, for our reported results in 2016, as a result of the NUG Contract, we recognized a receivable of $207 million (discounted), a pre-tax gain of approximately $191 million net of costs to mothball the units, and accelerated depreciation of $46 million. In 2017 and 2018, on a comparable basis, we record the payments we receive as revenues as a proxy for operating income, and continue to depreciate the facility until Dec. 31, 2018; and

(iv) On commissioning of South Hedland Power Station, we prepaid approximately $74 million of electricity transmission and distribution costs. Interest income is recorded on the prepaid funds. We reclassify this interest income as reduction in the transmission and distribution costs expensed each period to reflect the net cost to the business.

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

Year ended Dec. 31	**2017**[(1)]	2016[(1)]	2015[(1)]
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Net earnings attributable to non-controlling interests	**42**	107	94
Preferred share dividends	**30**	52	46
Net earnings (loss)	**(118)**	276	116
Adjustments to reconcile net income to comparable EBITDA			
Income tax expense	**64**	38	105
Gain on sale of assets and other	**(2)**	(4)	(262)
Foreign exchange (gain) loss	**1**	5	(4)
Net interest expense	**247**	229	251
Depreciation and amortization	**635**	601	545
Comparable reclassifications			
Decrease in finance lease receivables	**59**	57	23
Mine depreciation included in fuel cost	**75**	65	62
Australian interest income	**2**	-	-
Adjustments to earnings to arrive at comparable EBITDA			
Impacts to revenue associated with certain de-designated and economic hedges	**2**	26	60
Impacts associated with Mississauga recontracting[(2)]	**77**	(177)	-
Asset impairment charge (reversal)	**20**	28	(2)
Non-comparable portion of insurance recovery received	-	-	(18)
Maintenance costs related to the Alberta flood of 2013, net of insurance recoveries	-	-	(9)
Comparable EBITDA	**1,062**	1,144	867

Comparable EBITDA decreased by $82 million for the year ended Dec. 31, 2017, compared to 2016. The 2016 results were positively impacted by an $80 million non-cash accounting provision reversal relating to the Keephills 1 outage in 2013.

Comparable EBITDA at our US Coal, Canadian Gas, Australian Gas, and Wind and Solar segments were all up year over year, and collectively accounted for an increase of $95 million of comparable EBITDA. At US Coal, lower coal transportation costs and favourable mark-to-market on economic hedges that do not qualify for hedge accounting contributed to higher results. Our Canadian Gas operations benefited from the settlement of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor generating facilities, totalling $34 million, as well as the positive impact of the early shut down of our Mississauga gas plant in Ontario. Australian Gas' improved results were mainly due to the commissioning of our South Hedland Power Station in the third quarter. Higher volumes, lower cost of sales from renewable energy certificates, and lower operations, maintenance, and administration expenses were primary drivers of higher comparable EBITDA at our Wind and Solar segment.

(1) During the fourth quarter of 2017, we revised the way in which comparable EBITDA is reconciled to net earnings. Accordingly, prior years' results have been revised.

(2) Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2017, are as follows: revenue ($101 million), fuel and purchased power and de-designated hedges ($12 million), operations, maintenance, and administration ($3 million), and recovery related to renegotiated land lease ($9 million). Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2016, are as follows: net other operating income ($191 million) and fuel and purchased power and de-designated hedges ($14 million).

Comparable EBITDA for Canadian Coal was down $149 million from 2016. Comparable EBITDA in 2016 was positively impacted by the reversal of an $80 million non-cash accounting provision. In 2017, we recognized $40 million for OCA payments that were more than offset by lower prices due to the rolling off of higher priced hedges, higher coal costs caused by a higher strip ratio and lower equipment availability at our mine, and higher environmental compliance costs. EBITDA in Energy Marketing was down $7 million in 2017 compared to 2016. Results were impacted by unusual weather in the Northeast and the Pacific Northwest in the first quarter of 2017, but showed steady improvement in subsequent quarters.

Our overall results in 2017 also included costs of approximately $29 million relating to Project Greenlight, our transformation initiative. We estimate that the Project Greenlight initiatives generated between $35 million to $45 million of reduction in operations, maintenance, and administration ("OM&A") expenses and fuel costs or efficiency gains.

Funds from Operations and Free Cash Flow

FFO is an important metric as it provides a proxy for cash generated from operating activities before changes in working capital, and provides the ability to evaluate cash flow trends in comparison with results from prior periods. FCF is an important metric as it represents the amount of cash 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 FFO and FCF are not distorted by changes that we consider temporary in nature, reflecting, among other things, the impact of seasonal factors and timing of receipts and payments. FFO per share and 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 FFO and FCF.

Year ended Dec. 31	**2017**[1]	2016[1]	2015[1]
Cash flow from operating activities	**626**	744	432
Change in non-cash operating working capital balances	**114**	(73)	242
Cash flow from operations before changes in working capital	**740**	671	674
Adjustment:			
Decrease in finance lease receivable	**59**	57	23
Other	**5**	6	2
FFO	**804**	734	699
Deduct:			
Sustaining capital	**(235)**	(272)	(305)
Productivity capital	**(24)**	(8)	(6)
Dividends paid on preferred shares	**(40)**	(42)	(46)
Distributions paid to subsidiaries' non-controlling interests	**(172)**	(151)	(99)
Other	**(5)**	(4)	(4)
FCF	**328**	257	239
Weighted average number of common shares outstanding in the year	**288**	288	280
FFO per share	**2.79**	2.55	2.50
FCF per share[1]	**1.14**	0.89	0.85

The increase in FCF was driven by year-over-year stronger cash flow from operations of $69 million and lower sustaining capital expenditures. This was partly offset by higher distributions to our non-controlling partners at our gas and renewables businesses and higher capital allocated to productivity capital. FCF in 2016 and 2015 was also reduced by payments to the Market Surveillance Administrator ("MSA") of $25 million and $31 million, respectively.

(1) In the first quarter of 2017, we began deducting productivity capital in calculating FCF.

The table below bridges our comparable EBITDA to our FFO and FCF.

Year ended Dec. 31	2017[1]	2016[1]	2015[1]
Comparable EBITDA	**1,062**	1,144	867
Provisions	**(7)**	(114)	101
Unrealized (gains) losses from risk management activities	**(28)**	4	9
Interest expense	**(218)**	(229)	(233)
Current income tax expense	**(23)**	(23)	(18)
Realized foreign exchange gain (loss)	**15**	(5)	9
Decommissioning and restoration costs settled	**(19)**	(23)	(24)
Gain on curtailment and amendment of employee future benefit plans	**-**	-	(8)
Other cash and non-cash items	**22**	(20)	(4)
FFO	**804**	734	699
Deduct:			
Sustaining capital	**(235)**	(272)	(305)
Productivity capital	**(24)**	(8)	(6)
Dividends paid on preferred shares	**(40)**	(42)	(46)
Distributions paid to subsidiaries' non-controlling interests	**(172)**	(151)	(99)
Other	**(5)**	(4)	(4)
FCF	**328**	257	239

(1) During the fourth quarter of 2017 we removed certain comparable adjustments that reflect timing of payments and receipts, accordingly prior years' results have been restated.

Segmented Comparable Results

Canadian Coal

Year ended Dec. 31	**2017**	2016	2015
Availability (%)	**82.0**	85.3	84.3
Contract production (GWh)	**18,683**	19,823	20,256
Merchant production (GWh)	**3,786**	3,787	3,827
Total production (GWh)	**22,469**	23,610	24,083
Gross installed capacity (MW)(1)	**3,791**	3,791	3,786
Revenues	**999**	1,048	912
Fuel and purchased power	**510**	386	379
Comparable gross margin	**489**	662	533
Operations, maintenance, and administration	**192**	178	194
Restructuring provision	**-**	-	11
Taxes, other than income taxes	**13**	13	12
Net other operating income	**(40)**	(2)	(7)
Comparable EBITDA	**324**	473	323
Deduct:			
Sustaining capital:			
Routine capital	**22**	33	48
Mine capital	**28**	23	25
Finance leases	**14**	13	10
Planned major maintenance	**54**	100	107
Total sustaining capital expenditures	**118**	169	190
Productivity capital	**12**	1	2
Total sustaining and productivity capital	**130**	170	192
Provisions	**5**	85	(64)
Unrealized (gains) losses on risk management activities	**3**	7	4
Decommissioning and restoration costs settled	**11**	13	14
Canadian Coal cash flow	**175**	198	177

2017

Availability in 2017 was down compared to 2016 due to higher unplanned outages and derates due to coal supply disruptions at our mine during the last half of the year, which also resulted in lower production of 1,141 gigawatt hours ("GWh") year-over-year.

Comparable EBITDA for the year ended Dec. 31, 2017, decreased $149 million compared to 2016, due to the $80 million reversal of the Keephills 1 provision in the fourth quarter of 2016. As expected, fuel and purchased power was impacted by higher coal costs related to the expected higher strip ratio and higher environmental compliance costs in 2017. In addition, we incurred additional costs in the third quarter to mitigate the impact of lower productivity at our mine. OM&A increased $14 million year-over-year due mostly to contractor spend on Project Greenlight improvement initiatives ($20 million) and higher material and operating expenses ($5 million), and was partially offset by lower compensation ($11 million). See the Strategic Growth and Corporate Transformation section of this MD&A for further details. This year's results also included $40 million related to OCA payments included in net other operating income. We received our OCA payment in the third quarter.

(1) 2017 includes 560 MW for Sundance Units 1 and 2, which were both shut down and mothballed, on Jan. 1, 2018.

Sustaining and productivity capital expenditures for the year ended Dec. 31, 2017, were lower by $40 million compared to 2016, mainly due to the timing of major outages in 2017 and pit stops executed in 2016 on our Sundance 1 and 2 units.

2016

Production for the year ended Dec. 31, 2016, decreased 473 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 $150 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 2015's comparable EBITDA was reduced by $59 million due to this provision, which also included $11 million of restructuring costs. 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.

US Coal

Year ended Dec. 31	2017	2016	2015
Availability (%)	**66.3**	88.1	87.4
Adjusted availability (%)(1)	**86.2**	88.9	89.5
Contract sales volume (GWh)	**3,609**	3,535	2,868
Merchant sales volume (GWh)	**5,488**	4,896	5,484
Purchased power (GWh)	**(3,625)**	(3,854)	(3,329)
Total production (GWh)	**5,472**	4,577	5,023
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues	**437**	380	432
Fuel and purchased power	**293**	281	316
Comparable gross margin	**144**	99	116
Operations, maintenance, and administration	**51**	54	50
Restructuring provision	**-**	-	1
Taxes, other than income taxes	**4**	4	3
Comparable EBITDA	**89**	41	62
Deduct:			
Sustaining capital:			
Routine capital	**3**	3	2
Finance leases	**3**	3	3
Planned major maintenance	**29**	11	10
Total sustaining capital expenditures	**35**	17	15
Productivity capital	**3**	-	-
Total sustaining and productivity capital expenditures	**38**	17	15
Provisions	**-**	7	(7)
Unrealized (gains) losses on risk management activities	**10**	(13)	4
Decommissioning and restoration costs settled	**8**	9	9
US Coal cash flow	**33**	21	41

2017

Availability was down compared to 2016 due to a forced outage on Centralia Unit 1 in January. Both Centralia Units were taken out of service in February due to economic dispatch from low prices in the Pacific Northwest market. We performed major maintenance on both units during that time. The lower availability had a nominal impact on our results as our contractual obligations were supplied with less expensive power purchased in the market during the first half of the year.

Production was up 895 GWh in 2017 compared to 2016 due mainly to lower economic dispatching caused by higher prices. The increased generation was partially offset by higher unplanned and planned maintenance.

Comparable EBITDA increased by $48 million compared to 2016 due to increased sales volumes that led to increased margins from higher market prices and higher contract rates. Lower coal transportation costs and the favourable impact of mark-to-market (year-over-year gain of $13 million) on certain forward financial contracts that do not qualify for hedge accounting also positively impacted Comparable EBITDA.

Sustaining and productivity capital expenditures for year ended Dec. 31, 2017, increased $21 million compared to 2016 due to planned outages executed during the second quarter of 2017. Productivity capital was invested in the installation

(1) Adjusted for economic dispatching.

of inspection equipment to optimize heat rates on coal and improve air distribution systems. See the Strategic Growth and Corporate Transformation section of this MD&A for further details.

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 $19 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.

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

Canadian Gas

Year ended Dec. 31	**2017**	2016	2015
Availability (%)	**91.6**	95.7	95.6
Contract production (GWh)	**1,504**	2,784	3,697
Merchant production (GWh)	**244**	288	1,535
Total production (GWh)	**1,748**	3,072	5,232
Gross installed capacity (MW)[1]	**953**	1,057	1,057
Revenues	**430**	470	486
Fuel and purchased power	**113**	171	204
Comparable gross margin	**317**	299	282
Operations, maintenance, and administration	**53**	54	67
Restructuring provision	**-**	-	1
Taxes, other than income taxes	**1**	1	3
Comparable EBITDA	**263**	244	211
Deduct:			
Sustaining capital:			
Routine capital	**8**	7	4
Planned major maintenance	**22**	5	19
Total sustaining capital expenditures	**30**	12	23
Productivity capital	**2**	-	-
Total sustaining and productivity capital expenditures	**32**	12	23
Provisions	**3**	(2)	(1)
Unrealized (gains) losses on risk management activities	**7**	(2)	(6)
Decommissioning and restoration costs settled	**-**	1	1
Canadian Gas cash flow	**221**	235	194

2017

(1) 2017 excludes capacity of Mississauga, which was mothballed in early 2017. All years Include 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 was removed from our availability and production metrics effective Sept. 1, 2015.

Availability decreased approximately four per cent compared to 2016, primarily due to a planned major inspection at our Sarnia plant, the conversion to the peaking plant at Windsor and an unplanned steam turbine outage at Windsor.

Production in 2017 decreased 1,324 GWh compared to 2016, primarily due to changes in contracts at Mississauga and Windsor at the end of 2016.

Comparable EBITDA for 2017 increased by $19 million compared to 2016, primarily due to the settlement with the OEFC of the retroactive adjustment to price indices at Ottawa and Windsor and the positive impact from the temporary shutdown at our Mississauga gas facility, partially offset by unfavourable changes on unrealized mark-to-market positions in gas contracts that do not qualify for hedge accounting and the reduction in earnings from the change to a peaking contract at our Windsor facility. The Mississauga, Ottawa, Windsor and Fort Saskatchewan facilities are owned through our 50.01 per cent interest in TA Cogeneration L.P. ("TA Cogen").

Sustaining capital for the year ended Dec. 31, 2017, increased $18 million compared to the same period in 2016, primarily due to the planned major inspection at Sarnia and the base to cycling conversion project at Windsor, which was undertaken to increase its flexibility to respond to market prices.

<u>2016</u>

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 $33 million compared to 2015, as a 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 costs by more than $9 million in 2016, compared to 2015.

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.

Australian Gas

Year ended Dec. 31	2017	2016	2015
Availability (%)	**93.4**	93.1	92.4
Contract production (GWh)	**1,803**	1,529	1,381
Gross installed capacity (MW)[1]	**450**	425	348
Revenues	**180**	174	163
Fuel and purchased power	**12**	20	20
Comparable gross margin	**168**	154	143
Operations, maintenance, and administration	**31**	25	21
Taxes, other than income taxes	**-**	1	-
Comparable EBITDA	**137**	128	122
Deduct:			
Sustaining capital:			
Routine capital	**9**	3	4
Planned major maintenance	**1**	11	4
Total sustaining capital	**10**	14	8
Other	**-**	15	-
Australian Gas cash flow	**127**	99	114

2017

Production for 2017 increased by 274 GWh compared to 2016 due to the commissioning of our South Hedland Power Station on July 28, 2017, and an increase in customer load, partially offset by the early termination of our lease for our Solomon Power Station in November 2017. As a result of the early termination, we received US$325 million ($417 million) in the fourth quarter of 2017. Due to the nature of our contracts, the increase in customer load did not have a significant financial impact on our results as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA was up $9 million for 2017 compared to 2016 due to the commissioning of our South Hedland Power Station in July 2017, which was partially offset by the early termination of our lease for our Solomon Power Station in November 2017.

2016

Production for 2016 increased 148 GWh compared to 2015, mostly due to 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 2016 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.

(1) 2016 and 2017 figures include production capacity for the Solomon Power Station, which was accounted for as a finance lease. On Nov. 1, 2017, FMG repurchased the Solomon Power Station. The 2017 figures include capacity for the South Hedland Power Station, which achieved commercial operations on July 28, 2017.

Wind and Solar

Year ended Dec. 31	2017	2016	2015
Availability (%)	**95.8**	94.9	95.8
Contract production (GWh)	**2,362**	2,301	2,146
Merchant production (GWh)	**1,098**	1,212	1,060
Total production (GWh)	**3,460**	3,513	3,206
Gross installed capacity (MW)[(1)]	**1,363**	1,408	1,424
Revenues	**287**	272	250
Fuel and purchased power	**17**	18	19
Comparable gross margin	**270**	254	231
Operations, maintenance, and administration	**48**	52	48
Taxes, other than income taxes	**8**	8	7
Net other operating income	**-**	(1)	-
Comparable EBITDA	**214**	195	176
Deduct:			
Sustaining capital:			
Routine capital	**1**	2	1
Planned major maintenance	**10**	11	12
Total sustaining capital expenditures	**11**	13	13
Productivity capital	**2**	3	-
Total sustaining and productivity capital	**13**	16	13
Provisions	**-**	(1)	-
Wind and Solar cash flow	**201**	180	163

2017

Production for 2017 decreased by 53 GWh compared to 2016 as we sold the Wintering Hills wind facility in the first quarter of 2017. Generation from our other facilities was slightly higher than last year.

Comparable EBITDA for 2017 increased $19 million compared to 2016, primarily driven by higher volumes at contracted facilities, price increases on our contracted assets, higher prices in Alberta on our uncontracted assets and lower costs in our long-term service agreements.

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.

(1) The 2017 figure excludes capacity for the Wintering Hills wind facility, which was sold on March 1, 2017. Our 2015 capacity includes acquisitions completed during the second half of 2015.

Hydro

Year ended Dec. 31	2017	2016	2015
Contract production (GWh)	**1,866**	1,768	1,662
Merchant production (GWh)	**82**	88	86
Total production (GWh)	**1,948**	1,856	1,748
Gross installed capacity (MW)	**926**	926	926
Revenues	**121**	126	116
Fuel and purchased power	**6**	8	8
Comparable gross margin	**115**	118	108
Operations, maintenance, and administration	**37**	33	38
Taxes, other than income taxes	**3**	3	3
Net other operating income	**-**	-	(6)
Comparable EBITDA	**75**	82	73
Deduct:			
Sustaining capital:			
Routine capital, excluding hydro life extension	**8**	8	3
Hydro life extension	**-**	9	18
Planned major maintenance	**5**	10	10
Total before flood-recovery capital	**13**	27	31
Flood-recovery capital	**-**	2	4
Total sustaining capital expenditures	**13**	29	35
Productivity capital	**1**	-	-
Total sustaining and productivity capital	**14**	29	35
Hydro cash flow	**61**	53	38

2017

Production for 2017 increased by 92 GWh compared to 2016, primarily due to stronger water resources from spring run-off during the first nine months of 2017 in Alberta.

However, comparable EBITDA for the year ended Dec. 31, 2017 decreased by $7 million compared to 2016, due to higher operations, maintenance, and administration costs and a $3 million positive adjustment relating to a prior year metering issue at one of our facilities recorded in 2016.

Sustaining capital before insurance recoveries for 2017, decreased $16 million compared to 2016 due to lower expenditures on major overhauls. Life extension projects at Bighorn and Brazeau and flood recovery capital spend occurred in 2016.

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 as well as recognized business interruption recoveries in net other operating income (loss).

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.

Energy Marketing

Year ended Dec. 31	2017	2016	2015
Revenues and comparable gross margin	**69**	76	49
Operations, maintenance, and administration	**24**	24	15
Market Surveillance Administrator settlement	**-**	-	56
Comparable EBITDA	**45**	52	(22)
Deduct:			
Provisions	**(2)**	24	(28)
Unrealized (gains) losses on risk management activities	**8**	3	(11)
Energy Marketing cash flow	**39**	25	17

2017
Comparable EBITDA results were lower by $7 million compared to 2016, due to unfavourable first quarter of 2017 results impacted by warm winter weather in the Northeast, significant precipitation in the Pacific Northwest and reduced margins from our customer business.

2016
Comparable EBITDA from Energy Marketing increased $74 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. In 2015, we recognized $56 million in net other operating loss relating to the Alberta MSA settlement.

Corporate

2017
Our Corporate overhead costs were $14 million higher for the year ended Dec. 31, 2017, compared to 2016 mostly due to higher annual incentive compensations and Project Greenlight initiative fees. See the Strategic Growth and Corporate Transformation section of this MD&A for further details. The first quarter of 2017 also includes the reclassification of incentives for 2016 between our operational segments and our Corporate segment.

2016
Our Corporate overhead costs of $71 million were lower in 2016 compared to 2015 ($78 million) as we realized benefits of cost-efficiency initiatives and reduced restructuring costs 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 ratings 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.

(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, 2017, Dec. 31, 2016, and Dec. 31, 2015.

Funds from Operations Before Interest to Adjusted Interest Coverage

As at Dec. 31	2017	2016	2015
FFO	804	734	699
Add: Interest on debt and finance leases, net of interest income and capitalized interest	205	203	211
FFO before interest	1,009	937	910
Interest on debt and finance leases, net of interest income	214	219	220
Add: 50 per cent of dividends paid on preferred shares	20	21	23
Adjusted interest	234	240	243
FFO before interest to adjusted interest coverage (times)	4.3	3.9	3.7

Our target for FFO before interest to adjusted interest coverage is four to five times. The ratio improved significantly compared to 2016 due to better FFO delivered by the business and lower interest on debt as we continue to execute on our deleveraging plan.

Adjusted Funds from Operations to Adjusted Net Debt

As at Dec. 31	2017	2016	2015
FFO	804	734	699
Less: 50 per cent of dividends paid on preferred shares	(20)	(21)	(23)
Adjusted FFO	784	713	676
Period-end long-term debt(1)	3,707	4,361	4,495
Less: Cash and cash equivalents	(314)	(305)	(54)
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt(2)	(30)	(163)	(190)
Adjusted net debt	3,834	4,364	4,722
Adjusted FFO to adjusted net debt (%)	20.4	16.3	14.3

Our adjusted FFO to adjusted net debt ratio improved to 20.4 per cent, mainly due to the significant reduction in our net debt and the improvement in FFO. We reached the low end of our target range of 20 to 25 per cent in 2017 for the first time since 2011, due in part to our operations at South Hedland, which was fully commissioned in July 2017, and lower debt levels.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	2017	2016	2015
Period-end long-term debt(1)	3,707	4,361	4,495
Less: Cash and cash equivalents	(314)	(305)	(54)
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt(2)	(30)	(163)	(190)
Adjusted net debt	3,834	4,364	4,722
Comparable EBITDA	1,062	1,144	867
Adjusted net debt to comparable EBITDA (times)	3.6	3.8	5.4

Our adjusted net debt to comparable EBITDA ratio improved compared to 2016, mainly due to the significant reduction in our net debt during the year. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. We expect this metric

(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, 2017, Dec. 31, 2016, and Dec. 31, 2015.

to trend towards our targeted level due to the expected increase in comparable EBITDA from operations at South Hedland, which was fully commissioned in July 2017.

Ability to Deliver Financial Results

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

Year ended Dec. 31		2017(1)	2016	2015
Comparable EBITDA	Target	**1,025 - 1,135**	990 - 1,100	1,000 - 1,040
	Actual(2)	**1,062**	1,144	867
FFO	Target	**765 - 855**	755 - 835	720 - 770
	Actual	**804**	734	699
FCF	Target	**300 - 365**	250 - 300	265 - 270
	Actual	**328**	257	239

Significant and Subsequent Events

Normal Course Issuer Bid

On March 1, 2018, the Corporation announced that it intends to seek Toronto Stock Exchange ("TSX") acceptance of a NCIB. The Board has authorized the repurchases of up to 14,000,000 of its common shares, representing approximately five per cent of TransAlta's public float. Purchases under the NCIB are expected to be made through open market transactions on the TSX and any alternative Canadian trading platforms, based on the prevailing market price. Any Common Shares purchased under the NCIB will be cancelled.

Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire two construction-ready projects in the Northeast United States.

The wind development projects consist of: (i) a 90 MW project located in Pennsylvania that has a 15-year PPA and (ii) a 29 MW project located in New Hampshire with two 20-year PPAs. All three counterparties have Standard & Poor's credit ratings of A+ or better.

The total cost of the two projects is estimated to be US$240 million, of which approximately 70 per cent will be funded in 2018 and the remainder in 2019. The commercial operation date for both projects is expected during the second half of 2019.

TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.

Investment Highlights:

- accretive to cash available for distribution per share;
- aligns with the Corporation's and TransAlta Renewables' strategy of acquiring contracted renewable power generation assets that provide stable cash flow through long-term PPAs with creditworthy counterparties;
- delivers growth that creates long-term shareholder value;
- provides additional geographic and asset diversification; and
- the acquisition of the projects is subject to a number of closing conditions, including customary regulatory approvals and, in the case of the New Hampshire project, the receipt of a favourable regulatory determination in relation to the permitting of the project.

(1) Represents our original outlook. In the second quarter we reduced the following 2017 targets: Comparable EBITDA from the previously announced target range of $1,025 million to $1,135 million to $1,025 to $1,100 million, FFO from the previously announced target range of $765 million to $855 million to $765 million to $820 million FCF target range to $270 million to $310 million from the previously announced target range of $300 million to $365 million.

(2) 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 $1,064 million in 2016 and $926 million in 2015.

Early Redemption of Senior Notes Due 2018
On Feb. 2, 2018, the Corporation announced it called for the redemption of its outstanding US$500 million 6.65 per cent senior notes maturing May 15, 2018 (the "Senior Notes"). The Senior Notes will be redeemed on March 15, 2018, at a price equal to the greater of: (i) 100 per cent of the principal amount of the Senior Notes and (ii) the sum of the present values of the remaining scheduled payments of principal and interest thereon discounted to the redemption date on a semi-annual basis at the treasury rate plus 45 basis points, plus in each case, accrued interest thereon to the date of redemption.

Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements
On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C Power Purchase Arrangements ("Sundance PPAs") effective March 31, 2018.

The termination of the Sundance PPAs by the Balancing Pool was expected and the Corporation is working to ensure it receives the termination payment that it believes it is entitled to under the Sundance PPAs and applicable legislation. The expected impacts of the termination include approximately $215 million in compensation for the net book value of the assets as compared to the Balancing Pool's estimate of approximately $157 million. The Balancing Pool's estimate differs because it excludes certain mining assets that the Corporation believes should be included in the net book value calculation.

Transition to Clean Power in Alberta and Sundance Unit 1 Impairment Charge
I. Sundance and Keephills Units 1 and 2 Coal-to-Gas Conversion Strategy
On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. The strategy includes mothballing and retiring the following Sundance Units:

- retiring Sundance Unit 1 effective Jan. 1, 2018;
- temporarily mothballing Sundance Unit 2 effective Jan. 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 3 effective April 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 4 effective April 1, 2019, for a period of up to two years; and
- temporarily mothballing Sundance Unit 5 effective April 1, 2018, for a period of up to one year.

As a result of the clarity provided by the draft coal-to-gas conversion rules proposed by the Government of Canada, the Corporation has determined to accelerate the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, a year earlier than originally planned. Although not yet finalized, the Government of Canada has proposed coal-to-gas conversion rules that would extend the life of the Corporation's gas conversion units by five to ten years past their federal end of coal life, depending on their CO_2 emissions profile. The proposed rules would see the life of TransAlta's entire coal-fired fleet extended by an aggregate of approximately 75 years. In addition to extending their operating lives, the benefits of converting units to gas generation include: significantly lowering carbon intensities, emissions and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility.

Temporarily mothballing the combination of Sundance Units throughout 2018 and 2019 ensures that two Sundance Units can operate at high-capacity utilizations with lower costs throughout the period to 2020 when additional power will be needed in the Alberta market. The mothballing of the units will also assist the Corporation in its preparations for converting Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, thereby extending the useful lives of these assets until the mid-2030s.

II. Gas Supply for Coal-to-Gas Conversions
On Dec. 6, 2017, the Corporation entered into a letter of intent with Tidewater Midstream and Infrastructure Ltd. ("Tidewater") to construct a 120-kilometre natural gas pipeline from Tidewater's Brazeau River complex to the Corporation's generating units at Sundance and Keephills facilities. The pipeline is expected to provide initial capacity of 130 million cubic feet of gas per day by 2020, and to have expansion capability to 340 million cubic feet of gas per day. The initial capacity will support fuel blending, using a fuel combination of coal and gas for generation, which will reduce the marginal cost as well as emissions. The Corporation will have the option to acquire up to a 50 per cent interest in the pipeline, which, if exercised, would reduce the costs associated with the tolling agreement.

The decision to work with Tidewater advances the timeframe for the construction of the pipeline and permits the acceleration of plant conversions. TransAlta remains of the view that having at least two pipelines supplying natural gas would reduce operational risks and continues to advance discussions with other parties to construct additional pipelines to meet the remaining gas supply requirements for the facilities.

III. Sundance Units 1 and 2
Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide the Corporation with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively account for 560 MW of the 2,141 MW capacity at the Sundance power plant, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expired on Dec. 31, 2017.

In the second quarter of 2017, we recognized an impairment charge on Sundance Unit 1 in the amount of $20 million due to our decision to early retire Sundance Unit 1.

Notice of Termination of South Hedland PPA from Fortescue Metals Group Limited
On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidairy of the Corporation, received formal notice of termination of the South Hedland PPA from a subsidiary of FMG. The South Hedland PPA allows FMG to terminate the agreement if the power station has not reached commercial operation within a specified time period. FMG continues to be of the view that South Hedland Power Station has yet to achieve commercial operation.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies.

Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation will take all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA.

The South Hedland Power Station has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

Re-acquisition of Solomon Power Station
On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017 and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action to recover all, or a significant portion of, this amount from FMG.

TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, Kent Hills Wind LP ("KHWLP"), closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds will be used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project (upon meeting certain completion tests and other specified conditions). The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP. Proceeds of $30 million were classified as restricted cash as at Dec. 31, 2017 and will be released from the construction reserve account upon commissioning.

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million in total, which included the principal of $191 million, an early redemption premium of $6 million, and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

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. The sale closed March 1, 2017. Proceeds from the sale were used for general corporate purposes, including reducing our debt and funding future renewables growth. 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 were 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 for the year ended Dec. 31, 2016.

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, for a total amount of approximately $524 million. 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), 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 entered into a Memorandum of Understanding ("MOU") with the Government of Alberta 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:

- ensuring 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,
- developing 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 co-operation from the federal government, and
- developing 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 the NUG Contract with the IESO for our Mississauga cogeneration facility (the "Mississauga Facility"). The NUG Contract became effective on Jan. 1, 2017, and in conjunction with the execution of the NUG Contract, we agreed to terminate, effective Dec. 31, 2016, the Mississauga Facility's pre-existing contract with the OEFC, 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. On Nov. 9, 2017, TransAlta Renewables repaid the debentures early, for $218 million in total, comprised of the principal of $215 million and accrued interest of $3 million. The convertible debenture was scheduled to mature on Dec. 31, 2020.

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.

Alberta Market Surveillance Administrator Ruling

On July 27, 2015, the Alberta Utilities Commission ("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 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.

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2017, to Dec. 31, 2016:

Assets	Increase/ (decrease)	Primary factors explaining change
Trade and other receivables	230	Timing of customer receipts and seasonality of revenue
Assets held for sale	(61)	Closing of the sale of the Wintering Hills wind facility
Restricted cash	30	Restricted cash related to the KHWLP project financing
Finance lease receivables (long term)	(504)	Termination of Solomon finance lease ($424 million), unfavourable changes in foreign exchange rates ($23 million) and scheduled receipts ($58 million)
Property, plant, and equipment, net	(246)	Depreciation for the year ($635 million), unfavourable changes in foreign exchange rates ($43 million), retirement and disposals of assets ($36 million), and impairment charge ($20 million), partially offset by additions ($338 million) and revisions to decommissioning and restoration costs ($151 million)
Deferred income tax assets	(29)	Decreases in deductible temporary differences
Risk management assets (current and long term)	(131)	Contract settlements and unfavourable changes in foreign exchange rates, partially offset by market price movements
Other assets	(5)	Contractual payments received under Mississauga NUG contract ($116 million), offset by South Hedland long-term prepaid ($75 million) and loan receivable ($33 million)
Other	24	
Total decrease in assets	**(692)**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	182	Timing of payments and accruals
Dividends payable	(20)	Timing of the declaration of common dividends
Credit facilities, long term debt, and finance lease obligations (including current portion)	(654)	Repayments ($708 million) net of gain on cross currency swap and favourable effects of changes in foreign exchange rates ($214 million), partially offset by increase in the KHWLP project financing ($260 million) and increase credit facility ($26 million)
Income taxes payable	58	Disposition of Solomon Power Station
Decommissioning and other provisions (current and long term)	127	Impact of lower discount rate due to shortened useful lives on certain Alberta coal assets
Defined benefit obligation and other long term liabilities	29	Actuarial losses of $36 million partially offset by higher benefits contributions
Deferred income tax liabilities	(163)	Disposition of Solomon Power Station and decreases in taxable temporary differences
Risk management liabilities (current and long term)	27	Unfavourable market price changes, unfavourable foreign exchange and settled contracts
Equity attributable to shareholders	(185)	Net loss ($160 million), common share dividends ($34 million), preferred share dividends ($30 million), reallocation of equity in TransAlta Renewables ($48 million), partially offset by net other comprehensive income ($86 million)
Non-controlling interests	(93)	Distributions paid and payable ($172 million) and intercompany available-for-sale-investments ($11 million), partially offset by reallocation of equity in TransAlta Renewables ($48 million) and net earnings ($42 million)
Other	-	
Total decrease in liabilities and equity	**(692)**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the year ended Dec. 31, 2017, compared to the years ended Dec. 31, 2016 and Dec. 31, 2015:

Year ended Dec. 31	2017	2016	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of year	**305**	54	251	
Provided by (used in):				
Operating activities	**626**	744	(118)	Unfavourable change in non-cash working capital of ($187 million), partially offset by higher cash earnings ($69 million)
Investing activities	**87**	(327)	414	Proceeds on sale of Wintering Hills wind facility and Solomon power station disposition ($478 million), net loan receivable ($38 million), and restricted cash ($30 million)
Financing activities	**(703)**	(163)	(540)	Higher repayment of long-term debt ($726 million), lower issuance of long-term debt ($101 million), and lower proceeds on sale of non-controlling interest in subsidiary ($162 million), partially offset by lower borrowings under credit facility ($341 million), higher realized gains on financial instrument ($108 million), and lower dividends paid on common shares ($23 million)
Translation of foreign currency cash	**(1)**	(3)	2	
Cash and cash equivalents, end of year	**314**	305	9	

Year ended Dec. 31	2016	2015	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of year	**54**	43	11	
Provided by (used in):				
Operating activities	**744**	432	312	Favourable change in non-cash working capital of $315 million
Investing activities	**(327)**	(573)	246	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	(312)	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	(6)	
Cash and cash equivalents, end of year	**305**	54	251	

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. During the first quarter of 2017, we discontinued hedge accounting for a foreign currency fair value hedge that was in place on US$50 million of debt.

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.

When we do not elect hedge accounting, when we discontinue 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 foreign exchange rates related to these financial instruments are recorded in net earnings in the period in which they arise.

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, and currency exposures related to US-denominated debt. During the first quarter of 2017, we discontinued hedge accounting for certain foreign currency cash flow hedges that were in place on US$690 million of debt.

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 property, plant, and equipment ("PP&E").

When we do not elect hedge accounting, when we discontinue 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 US-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 US 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, 2017, Level III instruments had a net asset carrying value of $767 million (2016 - $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, 2016, with the exception of the changes to our hedge strategies for our US-dollar-denominated debt, as discussed above and in the Governance and Risk Management section of this MD&A.

2018 Financial Outlook

As a result of the Balancing Pool terminating the Sundance B and C PPAs, our capacity contracted by PPAs and longer-term contracts next year will drop by approximately 68 per cent. The average price of our short-term physical and financial contracts for 2018 is approximately $49 per megawatt hour ("MWh") in Alberta and approximately US$50 per MWh in the Pacific Northwest.

The following table outlines our expectations of key financial targets for 2018:

Measure	Target
Comparable EBITDA	$950 million to $1,050 million
FFO	$725 million to $800 million
FCF	$275 million to $350 million
Canadian Coal Capacity Factor	65 to 75 per cent
Dividend	$0.16 per common share annualized, 13 to 17 per cent payout of FCF

Operations

Availability and Capacity

Total availability of our Canadian coal fleet is expected to be in the range of 87 to 89 per cent in 2018. Availability of our other generating assets (gas, renewables) is expected to be in the range of 95 per cent in 2018. We will be accelerating our transition to gas and renewables generation, and have retired Sundance Unit 1 effective Jan. 1, 2018, and expect to be temporarily mothballing various Sundance Units during the first four months of 2018. See the Significant and Subsequent Events section of this MD&A for further details.

Fuel Costs

In Alberta, we expect fuel costs to approximate $37/tonne in 2018, but total fuel costs to be lower due to the mothballing of certain Sundance units. See the Significant and Subsequent Events section of this MD&A for further details.

In the Pacific Northwest, our US Coal mine, adjacent to our power plant, is in the reclamation stage. Fuel at US Coal has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost is expected to remain similar to that in 2017.

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 2018 objective for Energy Marketing is for the segment to contribute between $60 million to $80 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, the Australian dollar, and the euro 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 2018 is expected to be lower than in 2017 largely due to lower levels of debt. 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 $1.6 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 2018 and 2019.

Kent Hills 3 Wind Expansion

Total construction costs of our 17.25 MW Kent Hills 3 wind expansion in New Brunswick are expected to be approximately $41 million. To date we have spent $9 million. Our 17 per cent partner on the existing Kent Hills facilities is participating in the expansion project and also owns a 17 per cent interest. They will be funding their share of the total project costs. Our target completion date is the fourth quarter of 2018.

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 2016	Spent in 2017	Expected spend in 2018
Routine capital[1]	Capital required to maintain our existing generating capacity	83	**69**	**71 - 74**
Planned major maintenance	Regularly scheduled major maintenance	148	**121**	**71 - 74**
Mine capital	Capital related to mining equipment and land purchases	23	**28**	**32 - 34**
Finance leases	Payments on finance leases	16	**17**	**23 - 25**
Total sustaining capital		270	**235**	**195 - 205**
Flood-recovery capital	Capital arising from the 2013 Alberta flood	2	**-**	**-**
Total sustaining capital		272	**235**	**195 - 205**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	8	**24**	**20 - 30**
Total sustaining and productivity capital		280	**259**	**215 - 235**

Significant planned major outages for 2018 include the following:

- a major outage in our Canadian Coal segment, which one of our partners operates;
- a major outage at our US Coal segment scheduled for the second quarter;
- a major outage in our Canadian Gas segment related to our Sarnia facility; and
- distributed expenditures across our wind and hydro fleet.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of economic dispatching, is estimated as follows for 2018:

(1) Includes hydro life extension expenditures.

	Coal	Gas and Renewables	Total
GWh lost	130 - 170	600 - 700	730 - 870

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 $1.6 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.

Other Consolidated Analysis

Asset Impairment Charges and Reversals
As part of the Corporation's 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 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. Alberta Merchant CGU
During 2017, 2016, and 2015, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan ("CLP"), the future design parameters of the Alberta electricity market, and federal policies on the carbon levy and GHG emissions. Economic conditions also contributed to continued oversupply conditions and depressed market prices throughout 2015 to 2017. The Corporation assessed whether these factors, and events arising during the latter part of 2016, which are more fully discussed below, presented an indicator of impairment for its Alberta Merchant CGU. In consideration of the composition of this CGU, the Corporation 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 for any of these years, but for all years, a sensitivity analysis associated with these factors was performed to confirm continued existence of adequate excess of estimated recoverable amount over book value. This analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU in each of 2017, 2016, and 2015, due to the Corporation's large merchant renewable fleet in the province.

I. 2017

Sundance Unit 1

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintains the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU unit to 2021.

II. 2016

On Nov. 24, 2016, the Corporation reached an OCA with the Government of Alberta to receive annual cash payments of approximately $37.4 million, net to the Corporation in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, the Corporation 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 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 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 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 Government or the Alberta Electric System Operator ("AESO"), which is overseeing the development of the capacity market, to determine if a change is required. The Corporation has not modified its previous conclusions on the determination of the Alberta Merchant CGU.

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. In connection with this sale, the Wintering Hills assets were accounted for as held for sale at Dec. 31, 2016. As required, the Corporation assessed the assets for impairment before classifying them as held for sale. Accordingly, the Corporation 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 in 2016.

III. 2015

In 2015, the Government announced its 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 refined its approach to GHG emissions by announce the adoption of 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.

B. US Coal

The Corporation considered possible indicators of impairment at US Coal in 2017, 2016, and 2015, as discussed in more detail below.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded in 2017, 2016 or 2015. Any adverse change in assumptions, in isolation, would not have resulted in an impairment charge being recorded. The Corporation continues to manage risks associated with the CGU by optimizing its operating activities and capital plan.

The valuations are subject to measurement uncertainty based on the key assumptions outlined below, 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 plant, after its projected cessation of operation in its current form in 2025.

I. 2017

During 2017, the Corporation renegotiated rail transportation and coal supply agreements. Accordingly, the Corporation completed an estimate of the impact for the coal cost changes combined with updated power prices to determine whether the US Coal CGU had an indicator of impairment. The Corporation concluded that there is no indicator of impairment. The Corporation utilized the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$21.50 to US$34.81 per MWh
On-highway diesel fuel on coal shipments	US$2.08 to 2.29 per gallon
Discount rates	7.9 to 9.0 per cent

II. 2016

During 2016, the Corporation considered possible impairment at the US Coal CGU and found that the fair value less costs to sell approximated the then 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 2.09 per gallon
Discount rates	5.4 to 5.7 per cent

III. 2015

During 2015, the Corporation considered possible impairment at the US Coal CGU and found that the fair value, less costs to sell approximated the then 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 2.90 per gallon
Discount rates	5.2 to 6.2 per cent

In 2015, an impairment reversal of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

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, 2017, we provided letters of credit totalling $677 million (2016 - $566 million) and cash collateral of $67 million (2016 - $77 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:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Natural gas, transportation, and other purchase contracts	48	7	5	5	4	29	**98**
Transmission	9	6	6	3	-	-	**24**
Coal supply and mining agreements[1]	155	159	161	23	14	96	**608**
Long-term service agreements	108	50	41	31	15	35	**280**
Non-cancellable operating leases[2]	9	9	9	9	9	111	**156**
Long-term debt[3]	730	469	472	100	581	1,312	**3,664**
Principal payments on finance lease obligations	18	15	12	6	4	14	**69**
Interest on long-term debt and finance lease obligations[4]	177	153	125	102	95	692	**1,344**
Growth	27	-	-	-	-	-	**27**
TransAlta Energy Transition Bill	6	6	6	6	6	6	**36**
Total	**1,287**	**874**	**837**	**285**	**728**	**2,295**	**6,306**

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement, we have committed to fund US$55 million over the remaining life of the US Coal plant to support economic and community development, promote energy efficiency, and develop energy technologies related to the improvement of the environment. The Memorandum of Agreement 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.

Contingencies

I. Line Loss Rule Proceeding

TransAlta has been participating in a line loss rule proceeding (the "LLRP") before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by TransAlta for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if TransAlta and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil; TransAlta accordingly recorded an appropriate provision in 2017.

II. FMG Disputes

The Corporation is currently engaged in litigation with FMG as a result of their purported termination of the South Hedland PPA. In addition, FMG withheld approximately AUD58.2 million, including AUD43 million in tax applicable to the repurchase of the Solomon Power Station. TransAlta is seeking payment of all withheld amounts and has currently commenced proceedings to recover approximately AUD54.1 million by filing and serving FMG with a Writ and Statement of Claim on Nov. 17, 2017; TransAlta has also applied for summary judgment for this amount. The hearing is scheduled for
March 23, 2018.

(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.

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 Audit and Risk Committee ("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 that 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, 2017, is an estimated total upside of $156 million (2016 - $94 million upside) and total downside of $157 million (2016 - $89 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $130 million upside (2016 - $76 million upside) and $130 million downside (2016 - $69 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$25 to US$34 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 2017 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 2017, total depreciation and amortization expense was $708 million (2016 - $664 million), of which $75 million (2016 - $65 million) relates to mining equipment and is included in fuel and purchased power.

As a result of the OCA with the Government of Alberta described in the Significant and Subsequent Events section of this MD&A, we 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 some of our Alberta coal assets were reduced to 2030. See Accounting Changes section of this MD&A for further details.

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 2017 and 2016 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar CGU 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. During 2017, the

Corporation carried forward detailed recoverable amounts regarding the Hydro and Energy Marketing CGUs as specific criteria were met.

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 at our Wind and Solar CGU.

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 $24 million (2016 - $53 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2017. 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 $549 million (2016 - $712 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2017. 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, 2017, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $437 million (2016 - $293 million). During 2017, mainly as a result of the OCA, the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to use the 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1 billion, which will be incurred between 2018 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	3
Undiscounted decommissioning and restoration provision	10	2

Other Provisions

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

Accounting Changes

A. Current Accounting Changes

I. Change in Estimates - Useful Lives

As a result of the OCA with the Government of Alberta described in the Significant and Subsequent Events section of this MD&A, we 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 some of our Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017 increased in total by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to our decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see the Significant and Subsequent Events section of this MD&A for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, we extended the life of Sundance Unit 2 to 2021. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, decreased in total by approximately $4 million.

B. Future Accounting Changes

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

We have completed the review and accounting assessment of our revenue streams and underlying contracts with customers and the quantification of impacts. The majority of our revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms and from the sale of renewable energy certificates. IFRS 15 requires the application of a five-step model to determine when to recognize revenue, and at what amount. 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. Depending on whether certain criteria are met, revenue is recognized either over time, in a manner that depicts the entity's performance, or at a point in time, when control is transferred to the customer. We have not identified any significant differences in the timing or amount of recognition of revenue as a result of IFRS 15, with the exception of one difference, as discussed below.

IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer ("significant financing component"). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. We were required to apply this to one of our contracts with a customer. The application of the significant financing component requirements results in the recognition of interest expense over the financing period and a higher amount of revenue.

We have chosen to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the consolidated financial statements as at and for the year ended Dec. 31, 2018, will not be restated. Instead, we will recognize the cumulative impact of the initial application of the standard in retained earnings as at Jan. 1, 2018. The cumulative impact of applying the significant financing component requirements to the identified contract results in a $12 million (net of tax impacts) charge to retained earnings.

II. IFRS 9 *Financial Instruments*

In July 2014, the IASB issued the final version of IFRS 9, which replaces IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets, and a new hedge accounting model. IFRS 9 is required to be adopted retrospectively for annual periods beginning on or after Jan. 1, 2018 with early adoption permitted. IFRS 9 will be adopted by the Corporation on Jan. 1, 2018.

Under the new 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. The classification and measurement depends on the contractual cash flow characteristics of the financial asset and the entity's business model for managing the financial asset. The classification requirements for financial liabilities are largely unchanged from IAS 39. Based on the assessment performed to date, the Corporation's classification and measurement of financial assets is not expected to be materially affected by the initial application of IFRS 9.

The new general hedge accounting model is intended to be simpler and more closely focused 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. Based on its assessment to date, the Corporation is not expected to be materially affected by the new general hedge accounting model. However, where the Corporation uses foreign exchange forward contracts to hedge anticipated payments in foreign currency, and the hedged transaction results in a non-financial item, the reclassification of gains or losses on the hedges will be presented directly in the Statement of Changes in Equity as a reclassification from accumulated other comprehensive income.

The Corporation has completed its implementation plan, which included reviewing its various types of financial instruments to determine the impact of the new classification guidance, and assessing the historical credit loss data as well as considering reasonable and supportable forward-looking information that was available without undue cost or effort. There are no significant changes to classification and measurement identified. The Corporation is not expected to be materially impacted by the initial implementation of the expected credit loss impairment model. Ongoing disclosures are expected to be more extensive and will include information about the Corporation's risk management strategy, how the risk management activities may affect the amount, timing and uncertainty of future cash flows and the effect that hedge accounting has had on the statement of financial position, the statement of comprehensive income and the statement of changes in equity.

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 an initial scoping assessment for IFRS 16 and have prepared a detailed project plan. We anticipate that most of the effort under the implementation plan will occur in mid-to-late 2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our financial statements and disclosures.

Competitive Forces

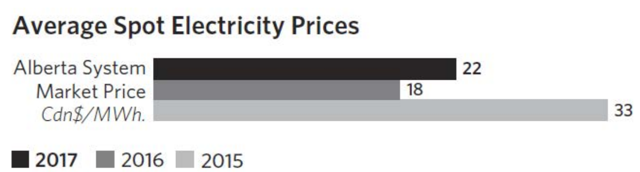
Demand and supply balances are the fundamental drivers of prices for electricity. Underlying economic growth is the main driver of longer-term changes in the demand for electricity, whereas system capacity, natural gas prices, GHG pricing, government subsidies, and renewable resource availability are key drivers of 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 59 per cent of our gross capacity is located in Alberta and more than 64 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. The Sundance 1 and 2 Alberta PPA expired at the end of 2017 and the Keephills 1 and 2, Sundance 3 to 6, Sheerness, and Hydro PPAs will expire at the end of 2020. During the third quarter of 2017, we received formal notice from the Balancing Pool of the termination of the Sundance 3 to 6 PPAs, effective March 31, 2018. In the fourth quarter of 2017, we announced our strategy of mothballing certain facilities as well as our plan to convert our coal-fired generation to gas-fired generation. See the Significant and Subsequent Events section of this MD&A for further details. Coal generation sold under certain 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 decreased approximately 1 per cent from 2015 to 2016, but recovered in 2017, increasing by approximately 4 per cent. The increase in demand was reflected in the average pool price, which increased from $18.28/MWh in 2016 to $22.19/MWh in 2017. However, the pool price was still relatively low due to the oversupply of electricity in the market. The softness in prices impacted merchant wind and hydro peaking, which are portions of our portfolio we cannot effectively hedge.

Our market share of offer control in Alberta in 2017 was approximately 12 per cent. After the termination of the Sundance 3 to 6 PPAs, our share of offer control is forecast to increase to approximately 22 per cent (16 per cent if the Sundance mothballed units are excluded from offer control).

In late November 2016, we announced that we had entered into the 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 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 AUC and the Balancing Pool. In this claim, the Attorney General challenged, among other things, the basis on which the buyers purported to terminate the PPAs and transfer their PPA obligations to the Balancing Pool. The Attorney General subsequently settled with the Buyers of the Sundance PPAs and, in the fourth quarter of 2017, the Balancing Pool confirmed the termination of the Keephills PPA. Accordingly, the Balancing Pool now acts as the buyer under the Sundance B, C, and Keephills PPAs.

Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool announced the complete termination of the Sundance PPAs, effective March 31, 2018. As of April 1, 2018, there will be no buyer under these PPAs. There has been no announcement yet concerning the Keephills PPA.

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.

Coal-to-Gas Conversions

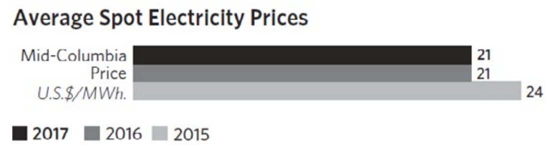
On Feb. 16, 2018, Environment and Climate Change Canada announced draft regulations to phase out coal-fired generation by 2030, as well as draft regulations for gas-fired electricity generation including provisions for the conversion of boiler units from coal-fired generation to natural gas-fired generation. The draft regulations were published in Canada Gazette I on Feb. 17, 2018. The rules for converted units will allow converted plants to operate for a set number of years following the end-of-life for the unit under the coal regulations based on a one-time performance test at the time of conversion. For our units, these rules will provide 5 to 10 additional years of operating life to each of our units, resulting in a cumulative life extension for our entire fleet of approximately 75 years, for a period of up to 15 years or until 2045, whichever comes first. We will continue to engage with the Government of Canada as the regulations move from draft to final publication in Canada Gazette II.

We are planning the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 to gas-fired generation in the 2021 to 2022 timeframe, thereby extending the useful lives of these units until the mid-2030s. We expect that the capacity of Sundance Units 3 to 6 and Keephills 1 and 2 will not change following conversion, which will result in a reduction of approximately 40 per cent of carbon emissions from these units while maintaining approximately 2,400 MWs in the Alberta power grid.

Our total capital commitment for the coal-to-gas conversions is expected to be approximately $300 million, mostly invested between 2021 to 2022. We anticipate funding the conversions with free cash flow at that time. These units are expected to provide low-cost capacity and to be competitive in the upcoming capacity market auctions. We expect the first auction to occur in 2019 for 2021 and that federal and provincial regulations will be adopted to facilitate coal-to-gas conversions. We continue to be engaged with government in the development of the required regulatory regime. This year, we spent $1 million to advance engineering for the conversion, and in 2018 we expect to spend $4 million.

US Pacific Northwest

Our capacity in the US 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 have 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 per year to 2024 and up to 300 MW for 2025. 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 2017, we entered into a long-term contract for our Fort Saskatchewan natural gas facility. We own a net 30 per cent of the facility. The contract has an initial 10-year term, commencing on Jan. 1, 2020, with an option for two five-year extensions. The contract allows our customer to continue to benefit from the operational flexibility of the plant. The current contract expires on Dec. 31, 2019. 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 resulted in the termination of the existing contract, which would have otherwise terminated in December 2018. 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

Our goal over the last three 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 certain rating agencies. We responded to this pressure by taking significant action starting in 2014 to reduce our indebtedness and strengthen our financial metrics.

Moody's lowered the rating of our senior unsecured debt to Ba1 with a stable outlook in December 2015. The direct financial impact of this downgrade has been limited. During 2017, Fitch Ratings reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- and changed its outlook from negative to stable, DBRS Limited changed the Corporation's Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating BBB to BBB (low) (changed to stable from negative), and Standard and Poor's reaffirmed our Unsecured Debt rating and Issuer Rating of BBB- but changed the outlook from stable to negative. 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.

Capital Structure

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

	2017		2016		2015	
As at Dec. 31	**$**	**%**	**$**	**%**	**$**	**%**
TransAlta Corporation						
Recourse debt - CAD debentures	**1,046**	**14**	1,045	12	1,044	12
Recourse debt - US senior notes	**1,499**	**19**	2,151	25	2,221	26
Credit facilities	**-**	**-**	-	-	315	4
US tax equity financing	**31**	**-**	39	-	50	-
Other	**13**	**-**	15	-	17	-
Less: cash and cash equivalents	**(294)**	**(4)**	(290)	(3)	(52)	-
Less: fair value asset of economic hedging instruments on debt(1)	**(30)**	**-**	(163)	(2)	(190)	(2)
Net recourse debt	**2,265**	**29**	2,797	32	3,405	39
Non-recourse debt	**208**	**3**	245	3	55	-
Finance lease obligations	**69**	**1**	73	1	82	1
Total net debt - TransAlta Corporation	**2,542**	**33**	3,115	36	3,542	40
TransAlta Renewables						
Credit facility	**27**	**-**	-	-	-	-
Less: cash and cash equivalents	**(20)**	**-**	(15)	-	(2)	-
Net recourse debt	**7**	**-**	(15)	-	(2)	-
Non-recourse debt	**814**	**11**	793	9	711	8
Total net debt - TransAlta Renewables	**821**	**11**	778	9	709	8
Total consolidated net debt	**3,363**	**44**	3,893	45	4,251	48
Non-controlling interests	**1,059**	**14**	1,152	14	1,029	13
Equity attributable to shareholders						
Common shares	**3,094**	**40**	3,094	36	3,075	36
Preferred shares	**942**	**12**	942	11	942	11
Contributed surplus, deficit, and accumulated other comprehensive income	**(710)**	**(9)**	(525)	(6)	(656)	(8)
Total capital	**7,748**	**100**	8,556	100	8,641	100

We continued down our path of strengthening our financial position during 2017 and have reduced our total consolidated net debt by almost $900 million since the end of 2015. In the second quarter of 2017, we made a scheduled US$400 million U.S. Senior Note repayment using existing liquidity. This repayment was hedged with a cross-currency swap entered into on issuance of the debt that effectively reduced our Canadian dollar repayment by approximately $107 million. On Oct. 2, 2017, we closed a $260 million bond offering secured by our Kent Hills Wind Farms, and used $197 million of the proceeds to early redeem all of CHD's outstanding non-recourse debentures. In February 2018, we announced the early redemption of US$500 million of our Senior Notes due in May 2018. See the Significant and Subsequent Events section of this MD&A for further details.

Throughout 2016 and 2017, we continued implementing our strategy to raise debt secured by our contracted cash flows and completed the following debt offerings:

- a project-level bond in the amount of $260 million, with principal and interest payable quarterly, maturing on Nov. 30, 2033, secured by our Kent Hills Wind Farms;
- a non-recourse bond in the amount of $202.5 million, with principal and interest payable quarterly, maturing on

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

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.

These actions align with our strategy of issuing project-level amortizing debt to proactively manage upcoming debt maturities.

During 2019 to 2020, we have approximately $941 million of debt maturing. We expect to refinance some of these upcoming debt maturities by raising $300 to $400 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 three years will be allocated to debt reduction.

During 2017, we received US$325 million ($417 million) from FMG for the sale of the Solomon Power Station and expect $215 million on March 31, 2018, relating to the Sundance Unit 3 to 6 PPA terminations from the Balancing Pool. On Feb. 2, 2018, we announced our intent to use our existing liquidity to early repay a US$500 million U.S. Senior Note maturing in May 2018. For further details see the Significant and Subsequent Events section of this MD&A. These events provide us more financial flexibility in executing our deleveraging plan.

On Jan. 18, 2017, we renewed a US base shelf prospectus that allows for the issuance of up to $2.0 billion aggregate principal amount (or its equivalent in other currencies) of common shares, first preferred shares, warrants, subscription receipts and debt securities from time to time. We also have a Canadian base shelf prospectus, which allows for the issuance of common shares, first preferred shares, warrants, subscription receipts and debt securities from time to time. The specific terms of any offering of securities is to be determined at the date of issue.

On March 1, 2018, we announced our intention to seek Toronto Stock Exchange acceptance of a NCIB. See the Significant and Subsequent Events section of this MD&A for further details.

The weakening of the US dollar has decreased our long-term debt balances by $113 million in 2017. Almost all our U.S.-denominated debt is hedged[(1)] either through financial contracts or net investments in our U.S. operations. During the year, these changes in our US-denominated debt were offset as follows:

As at Dec. 31	**2017**	2016
Effects of foreign exchange on carrying amounts of US operations (net investment hedge) and finance lease receivable	**(61)**	(35)
Foreign currency economic cash flow hedges on debt[(1)]	**(45)**	(29)
Economic hedges and other	**(7)**	(3)
Total	**(113)**	(67)

Our credit facilities provide us with significant liquidity. On July 24, 2017, TransAlta Renewables entered into a $500 million syndicated credit agreement. At the same time, we agreed to reduce our facility by the same amount so that consolidated syndicated credit facilities remained constant at $1.5 billon. As a result, at Dec. 31, 2017, we maintained our total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities. We are in compliance with the terms of the credit facilities. In total, $1.4 billion (Dec. 31, 2016 - $1.4 billion) was available for use. At Dec. 31, 2017, the $0.6 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). These facilities are comprised of a $1 billion committed syndicated bank facility expiring in 2021, a $500 million committed syndicated bank facility expiring in 2021 at TransAlta Renewables, one bilateral credit facility of US$200 million expiring in 2020, and three bilateral credit facilities totalling $240 million, expiring in 2019.

(1) During the first quarter of 2017, we discontinued hedge accounting on certain US-denominated debt hedges. The foreign currency derivatives remain in place as economic hedges. See the Financial Instruments section of this MD&A for further details.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP, and Mass Solar non-recourse bonds of $1,021 million (Dec. 31, 2016 - $845 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the 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. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2018. At Dec. 31, 2017, $35 million (Dec. 31, 2016 -$24 million) of cash was subject to these financial restrictions. In addition, we have $30 million of proceeds from the KHWLP project financing that are being held in a construction reserve account, which will be released upon certain conditions, including commissioning, being met.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2017. However, as at Dec. 31, 2017, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letters of credit and was not available for general use.

Working Capital

Including the current portion of long-term debt, the excess of current assets over current liabilities was $101 million as at Dec. 31, 2017 (2016 - $337 million), a decrease of $226 million. Our working capital decreased year-over-year due to higher current income taxes payable as a result of the sale of the Solomon Power Station and the increase in long-term debt due within the next year (this year, we have a US$500 million senior note due; whereas last year, a US$400 million senior note was due). Last year, working capital included $61 million of assets classified as held for sale related to the Wintering Hills wind facility. Excluding the current portion of long-term debt of $747 million, the excess of current assets over liabilities was $848 million as at Dec. 31, 2017 (2016 - $976 million), a decrease of $128 million, mainly due to the higher 2017 current income taxes payable and the $61 million of assets related to Wintering Hills in 2016's working capital.

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. Our Series C and Series E Cumulative Redeemable Rate Reset Preferred Shares failed to receive the required number of minimum votes in 2017 to give effect to conversions into Series D and Series F; respectively, accordingly, both the Series C and Series E Preferred Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The Series G preferred shares will reset in 2019.

The following table outlines the common and preferred shares issued and outstanding:

As at	**March 1, 2018**	**Dec. 31, 2017**	Dec. 31, 2016
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**287.9**	**287.9**	287.9
Preferred shares			
Series A	10.2	10.2	10.2
Series B	1.8	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

Non-Controlling Interests

As of Dec. 31, 2017, we own 64.0 per cent (2016 – 64.0 per cent) of TransAlta Renewables. The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's common share equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The stable and predictable cash flows generated by TransAlta Renewables' assets have attracted favourable equity valuations from investors, allowing TransAlta the potential to raise equity capital.

In 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. On Nov. 9, 2017, TransAlta Renewables paid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. 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.

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. In 2016, we recontracted our Mississauga cogeneration, which resulted in a pre-tax gain of approximately $191 million, accelerated depreciation of $46 million, and recognized a fuel charge for the de-designation of gas hedges of $14 million. The Mississauga, Ottawa, Windsor, and Fort Saskatchewan facilities are owned through our 50.01 per cent interest in TA Cogen. 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	**2017**	2016	2015
Interest on debt	**218**	218	218
Interest income	**(7)**	(2)	(2)
Loss on redemption of bonds	**6**	1	-
Capitalized interest	**(9)**	(16)	(9)
Interest on finance lease obligations	**3**	3	4
Credit facility fees, bank charges, and other interest	**18**	19	10
Keephills 1 outage interest accruals (reversals)	**-**	(10)	9
Other	**(3)**	(4)	-
Accretion of provisions	**21**	20	21
Net interest expense	**247**	229	251

In 2017, we refined our categorization of interest on debt, mainly to report separately credit facility fees. Prior periods have been revised accordingly.

Net interest expense increased during 2017 compared to 2016, due to lower capitalized interest and the redemption premium recognized on the early redemption of the CHD debentures, which more than offset higher interest income. During 2016, reversals of interest previously accrued relating to our Keephills 1 outage arbitration reduced interest expense.

Net interest expense decreased in 2016 compared to 2015, primarily as a result of higher capitalized interest relating to the South Hedland Power Station 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 credit facility fees, bank charges, and other interest.

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 2017 common and preferred shares dividends declared each quarter:

Declaration date	Common dividends per share	Preferred Series dividends per share				
		A	B	C	E	G
April 19, 2017	0.04	0.16931	0.15645	0.28750	0.31250	0.33125
July 18, 2017	0.04	0.16931	0.16125	0.25169	0.31250	0.33125
Oct. 30, 2017	0.04	0.16931	0.17467	0.25169	0.32463	0.33125

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

On Feb. 2, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on April 1, 2018. The Corporation also declared a quarterly dividend of $0.16931 on the Series A preferred shares, $0.17889 on the Series B preferred shares, $0.25169 on the Series C preferred shares, $0.32463 on the Series E preferred shares, and $0.33125 on the Series G preferred shares, all payable on March 31, 2018.

Non-Controlling Interests

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2017, decreased by $65 million compared to 2016. Net earnings were negatively impacted by the impairment of TransAlta Renewables' investment in the Australian business recognized as a result of the sale of the Solomon Power Station to FMG and the purported termination of its South Hedland PPA and by higher net interest expense due to higher outstanding borrowings. The Mississauga recontracting has also impacted net earnings, as we recognized a $191 million gain in 2016's results.

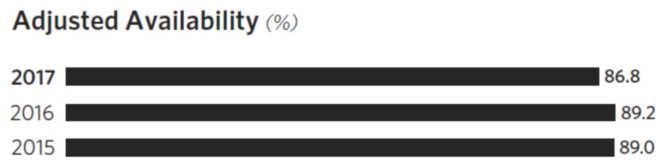
Reported net earnings attributable to non-controlling interests for the year ended Dec. 31, 2016, increased $13 million to $107 million compared to 2015, primarily due to the public offering of additional common shares by TransAlta Renewables to finance its investments in the Australian and Canadian portfolios in May 2015 and January 2016, respectively. Included in net earnings for 2016 was recognition of the non-controlling interests of $191 million gain due to the Mississauga recontracting.

Power Generating Portfolio

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 86 to 88 per cent for 2017.



Our availability in 2017, after adjusting for economic dispatching at US Coal, was 86.8 per cent (2016 – 89.2 per cent, 2015 – 89.0 per cent) and was lower compared to last year. The main causes of the decrease were higher outages and derates at Canadian Coal, planned maintenance at our Sarnia facility, and the change at Windsor to a peaking facility. Windsor's base to cycling conversion project also impacted the year-to-date availability. Lower availability had a minimal impact on our results due to current low prices in Alberta, the Pacific Northwest, and Ontario.

Production for the year ended Dec. 31, 2017, decreased 1,257 GWh compared to 2016. The cessation of operations at our Mississauga gas plant effective Jan. 1, 2017, and higher outages and derates at Canadian Coal were the main drivers of the production decrease during the year. This was partially offset by higher generation from Australia due to the commissioning of South Hedland and stronger customer demand. U.S. Coal had higher production compared to 2016 as a result of lower economic dispatching in the first quarter of 2017 due to slightly higher prices. Higher water resources at Hydro also contributed to higher production in 2017. In accordance with the terms of Mississauga's new contract with Ontario's IESO, we will continue to receive monthly capacity payments from the IESO until Dec. 31, 2018.

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. In 2017, we initiated Project Greenlight across the entire organization with the intent to deliver committed improvements across the Corporation, including increased generation efficiency, lower cost and improved heat rates. Since 2015, we have reduced our OM&A generation costs by approximately 7 per cent from $418 million to $383 million.

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

Year ended Dec. 31	2017	2016	2015
Generation comparable OM&A	**412**	396	418
Greenlight transformation costs included in OM&A			
Canadian Coal	**(20)**	-	-
US Coal	**(2)**	-	-
Gas, Wind and Solar, and Hydro	**(7)**	-	-
Adjusted generation comparable OM&A	**383**	396	418

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	2017	2016	2015
Routine capital	**69**	83	101
Mine capital	**28**	23	25
Planned major maintenance	**121**	148	162
Finance leases	**17**	16	13
Total sustaining capital expenditures	**235**	270	301
Productivity capital	**24**	8	6
Flood-recovery capital	**-**	2	4
Total sustaining, productivity, and flood recovery capital expenditures	**259**	280	311
Insurance recoveries of sustaining capital expenditures	**-**	(1)	(25)
Net amount	**259**	279	286

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

Year ended Dec. 31	2017	2016	2015
GWh lost(1)	**1,234**	938	1,409

Total net sustaining and productivity capital expenditures were $20 million lower compared to 2016. While we decreased our target for sustaining capital for the year, we increased the productivity capital expected spend for 2017, as these expenditures relate to the funding of some Project Greenlight transformation initiatives. In certain cases, payback is expected to be achieved within two years. We completed planned major outages at Sundance Units 5 and 6, Keephills Unit 2, Keephills Unit 3, Sheerness Unit 1, Centralia Unit 2, Sarnia, and Windsor, and we completed an overhaul to one of our draglines at our Highvale mine.

Strategic Growth and Corporate Transformation

Acquisition of Two U.S. Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced that it had entered into an arrangement to acquire two wind construction-ready projects in the United States. See the Significant and Subsequent Events section of this MD&A for further details.

South Hedland Power Station and Conversion of Class B Shares

Our South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, we converted our 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, our common share equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables. TransAlta Renewables also announced an increase in its monthly dividend rate of approximately 7 per cent.

On Aug. 1, 2017, FMG notified TransAlta that in its view the South Hedland Power Station has not yet satisfied the requisite performance criteria under the South Hedland PPA between FMG and TransAlta. In our view, all conditions to establish commercial operations have been fully satisfied under the terms of the PPA with FMG and TransAlta. Horizon Power, the local utility and pricing offtaker, has not disputed commercial operation. On Nov. 13, 2017, FMG issued a notice of termination of the PPA.

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

Our view is that the contract termination is invalid and, as such, we have continued to invoice FMG for monthly capacity. On Dec. 4, 2017, we commenced proceedings in the Supreme Court of Western Australia to recover amounts invoiced under the PPA to FMG.

Kent Hills Wind Project
During the second quarter, TransAlta Renewables entered into a long-term contract with the New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind project. At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035, matching the life of the Kent Hills 2 and Kent Hills 3 wind projects.

The additional 17.25 MW at Kent Hills is an expansion of our existing Kent Hills wind farms, increasing the total operating capacity of the Kent Hills wind farms to approximately 167 MW. We expect to begin the construction phase in the spring of 2018.

On Oct. 2, 2017, TransAlta Renewables' indirect majority-owned subsidiary, KHWLP, closed an approximate $260 million bond offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at an annual rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. The proceeds from the financing were used to early repay maturing debt and to fund the expansion of the project, net of $30 million held in a construction reserve account with the remainder, being distributed to the partners in the Kent Hills wind project.

Brazeau Hydro Pumped Storage
The Brazeau Hydro Pumped Storage project is an innovative way to generate and shape clean electricity. It will store water that can be used to both generate power when it is needed and store excess power supply when demand is low. When there is excess renewable generation in periods of low demand, water will be pumped from the lower reservoir and stored in the upper reservoir to be used later. When demand is high and generation from other renewables generation is not sufficient, water will flow back through a turbine using gravity to generate clean electricity. The Brazeau Hydro Pumped Storage project is a focus for us, as it has existing infrastructure that reduces the cost and environmental footprint of the project, is situated close to existing transmission infrastructure, and allows for increased renewables development by balancing intermittent generation from wind and solar.

We are currently working to secure a path that will advance our investment in the project and secure a long-term contract for the project. The Brazeau Hydro Pumped Storage project is expected to have new capacity ranging between 600 MW to 900 MW, bringing the total Brazeau facility to 955 to 1,255 MW, post-completion. We estimate an investment in the range of $1.8 billion to $2.5 billion and expect construction to begin upon receipt of a long-term contract and regulatory approvals, between 2020 and 2021, with operations to commence in 2025. In 2017, we invested approximately $6 million to advance the environmental study, work with stakeholders and execute geotechnical work to help further our design and construction phase.

Other Growth Projects
We are advancing our plans to build, own and operate the following growth projects:

- The Antelope Coulee Wind project - a wind project located in southwest Saskatchewan, comprised of up to 55 turbines, with a total capacity of between 100 MW to 200 MW, depending on the approved size of the project. If successful, construction could begin in 2020 with a proposed commercial operation date of no later than September 2021. If built, the project is expected to produce up to 800,000 MWh of electricity annually, enough to power over 80,000 homes.
- The Garden Plain Wind project – a wind project located near Drumheller, Alberta, comprised of 36 turbines, with a total capacity of approximately 130 MW. We are in the late stages of finalizing the project design and are preparing to submit an application to the AUC for construction and permitting approval, which is expected in March 2018. If built, the project is expected to produce 455,000 MWh of electricity annually, enough to power around 50,000 homes.

- The New Colony Wind Farm - a greenfield wind project located in Martinsdale, Montana, comprised of 7 turbines, with a total capacity of approximately 23.1 MW. The project is in late stages of development and if built, the project is expected to produce 75,000 MWh of energy annually.
- Goonumbla Solar Project – a solar project located in New South Wales, roughly 350 kilometres from Sydney, consisting of photovoltaic solar panels with a total capacity of 70 MW. The project is permitted and has an interconnection agreement in place with a transmission operator. An experienced engineering, procurement, and construction contractor has been selected.

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 PPAs 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 beginning of 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.

Project Greenlight

Our transformation project is a top priority for us. Driven by engagement from all employees, the intent is to deliver ambitious improvements in every part of the Corporation. Initiatives include increasing revenue, improving generation, reducing operating and maintenance costs, reducing overhead costs and financing costs, and optimizing our capital spend. We expect Project Greenlight to deliver sustainable pre-tax savings of approximately $50 million to $70 million annually, commencing in 2018. We are on track to achieve our expected annual savings targets. In 2017, the cost of the program was largely offset by the cost reductions and productivity gains. We expect to invest a further $10 million to $20 million on this program in 2018. We also expect to spend $20 million to $30 million related to productivity capital in 2018.

Contractual Profile

Approximately 65 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. During the fourth quarter of 2017, we entered into a long-term contract for the Fort Saskatchewan natural gas facility, commencing Jan. 1, 2020. The contract has an initial 10-year term. In 2016, we entered into a long-term contract for the Akolkolex hydro facility in B.C., expiring in 2045. Our South Hedland Power Station reached commercial operations on July 28, 2017, and is expected to add stable contracted cash flows until the end of its 25-year contract life. In 2015, 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 19 years.

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 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 2015, we executed an extension to our PPA 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 four years, we have nearly tripled the weighted average remaining contractual life of our gas fleet from six years to 19 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 on our human capital performance are an engaged workforce and keeping our employees safe.

As at Dec. 31, 2017, we had 2,228 (2016 - 2,341) active employees. This number has decreased by four per cent since the previous year, following various restructuring initiatives to reduce costs and increase efficiency.

Approximately 57 per cent of our employees are 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 value creation. Our corporate culture 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. 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.

Our organizational structure consists of six levels, which helps facilitate pace and decision-making in our organization. Our business operates in a decentralized, business-centric model, with Coal & Mining, Gas & Renewables, Australia, and Energy Marketing and Trading defined as our four primary businesses. Our Corporate function oversees our business and provides strategic alignment.

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 retirement savings plans. We have registered pension plans in Canada and the US, as well as a superannuation plan in Australia. The plans cover substantially all employees of the Corporation, its domestic subsidiaries, and specific named employees working internationally. These plans have defined benefit ("DB") and defined contribution ("DC") options, and in Canada there was an additional DB supplemental pension plan ("SPP") for members whose annual earnings exceed the Canadian income tax limit. The DB SPP was closed as of Dec. 31, 2015, and a new DC SPP commenced for only executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered in the DB SPP. The Australian superannuation plan is compulsory for employers with contributions required at a rate set by the government, currently 9.5 per cent of employees' wages and salaries.

The Canadian and US defined benefit pension plans are closed to new entrants, with the exception of the Highvale pension plan acquired in 2013. The US 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 and actuarial valuations. 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 non-registered and 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.

Talent and Employee Development

Talent and employee development is a viewed as a key pillar of organizational health. In 2017, we conducted a Change Leadership Forum for our managing directors and in 2018 this program will be extended to managers. The two-day session is focused on organizational transformation with an emphasis on identifying root causes of barriers related to driving change.

In 2017, we completed a six-month (intermittent) leadership training program, called Elevate, for our middle management. This resulted in training approximately 75 leaders in the Corporation. The program was focused on establishing a learner's mindset, building trust and influence, strengths-based leadership, being transparent, providing feedback, collaboration as a team and innovation. In 2018, we are continuing this program with a focus on training our professionals and subject matter experts. Our professionals will be supported by our leaders who completed the program in 2017.

In addition to Elevate, we launched a two-day leadership program in 2017 for all of our employees. The program, called Execution Engine, was designed to build capabilities for our people to create an organization that is both efficient and adaptive, while living our values. The training program was built on research into what is needed for our people to help drive and sustain change. With everyone taking this course (approximately 700 employees or 30 per cent in the past nine months) the learning has become part of how we work. Employees learn project management (i.e., idea generation, planning, problem solving and prioritization), effective communication (i.e., presentations, meetings, emails), how to get the best out of people (coaching and influencing) and health (organizational health and personal resilience).

Safety

The safety of our people, communities and environment is one of our seven core values. 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 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 the Corporation.

Our approach to safety was revised in 2015 from only a focus on occupational safety to a focus on both occupational safety and preventative maintenance (targeted with safety in mind). With collaboration from ScottishPower, who achieve leading safety performance, we launched our total safety management policy, which is a two-pronged approach. The policy builds on our occupational safety program, Target Zero, which is focused on protecting our workers on site, through personal protection equipment, inspections, safety controls, job safety analyses, field-level hazard assessments and safety communications. The policy is supplemented by our Operational Integrity program, which is focused on preventing all hazards from equipment, through definition and measurement of safety-critical performance measures and operating limits. Another way to think of Operational Integrity is preventative safety.

This policy and approach has led to progress and results. In 2017 our Injury Frequency Rate ("IFR") was 0.72 (2016 - 0.85). IFR is defined as the number of injuries (lost-time and medical) for every 200,000 hours worked. Our ultimate goal is to achieve zero injury incidents, but annually we seek improvement over the prior year. Fortunately, we have experienced no fatalities during the last three years. Our target IFR in 2018 is 0.53, a 20 per cent reduction over 2017 performance.

In 2017, we introduced a new key performance indicator to help us further improve our safety performance. Total Incident Frequency ("TIF") tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids) relative to employee hours worked. First aids can be minor (such as a cut or scratch) nevertheless, incident awareness and understanding provide us with preventative safety knowledge, which translates into education for employees and subsequently injury avoidance. Our TIF in 2017 was 3.54. We are targeting a TIF of 2.83 in 2018, a 20 per cent reduction over 2017 performance. As noted above, our long-term goal is zero.

Year ended Dec. 31	**2017**	2016	2015
IFR	**0.72**	0.85	0.75
TIF	**3.54**	-	-

We reward our plants for safety leadership annually, and this year our President's Award for Safety Leadership went to the Ottawa Health Sciences Centre Cogeneration Team. Our cogeneration facility in Ottawa supports the Ottawa Hospital. This facility and its team have logged zero lost-time injuries for more than six years — and the effort didn't only come from our employees. More than 100 contractors, logging more than 50,000 contractor hours, completed their work without a single lost-time injury. Our team at our Sarnia facility also displayed great safety leadership in 2017. The team had 300,000 worker exposure hours in 2017 without injury and has had 1.15 million exposure hours since an injury last occurred.

Intellectual Capital

Intellectual capital at TransAlta is another key to value creation. Our employee culture is supported by a long-term and sustainable approach, as evidenced by over 100 years in business. A long-term commitment lends itself to goodwill and brand recognition, something we value and don't take for granted. We believe our low cost and clean power strategy, supported by our internal values and sustainable approach to business, will help support and continue to increase our brand recognition positively.

The experience and acumen of our employees further enhances our capital value creation. This is evidenced by our 18-month ongoing internal transformation, called Project Greenlight. This project is focused on bottom-up innovation, specifically fostering a culture of idea generation, development of ideas into projects with defined KPIs, milestones and execution or delivery dates, and ongoing project management to ensure success. Where we fail, we idea generate, build and test again. Since inception, we have completed 900 bottom-up initiatives.

We believe that global marketplace disruption is here to stay and we recognize that to adapt to the pace of change and remain competitive, our employees must be nimble, adaptive and work smarter and faster. For further details on our investment in our workforce, please see the Talent and Employee Development discussion in the Human Capital subsection of this MD&A.

In addition, our teams continuously explore the 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.

The following are further examples of how we have developed innovative solutions to optimize and maximize value from our fleet:

Operations Diagnostic Centre
TransAlta has run 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
Our Operational Integrity program is the integration of sustainability, specifically safety, into asset management. It is a program designed to achieve process and equipment safety by understanding and monitoring of key operational risks and implementation of mitigation measures. Consider it proactive safety. In 2017, we put into place our Total Safety Management System, which integrates our work in Process Safety with our existing strength in Occupational Safety programs. We continue to see a positive increase in self-reporting and addressing process safety hazards as awareness and new tools are being introduced. This is evidenced by our trend in safety incidents, which decreased in 2017 to an IFR of 0.72 (0.85 in 2017). This was one of our best safety performance years in our history. Our goal is zero and the Operational Integrity program is a tried and tested tool to help propel us closer to this goal.

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 and developer 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 a 21 MW solar facility in Massachusetts.

As we move towards our vision of becoming the leading clean power corporation in Canada by 2030 we continue to seek solutions to innovate and create value for investors, society and the environment. This is evidenced by our announcements of the accelerated coal-to-gas conversion plans, the expansion of our Kent Hills wind farm in New Brunswick, the proposed solar development in New South Wales, Australia, and the exploration of our proposed Brazeau hydro expansion, a 600-900 MW pumped hydro expansion that will double our hydro capacity in Alberta. 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 communications 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 2017 we reduced the risk of cliff jumping on or close to our hydro facilities west of Calgary. We increased awareness through a collaborative multi-agency approach and tightened up the boundaries with the introduction of natural resources, such as foliage and large boulders, to prevent vehicular access to jump spots.

A safety signage project was launched across hydro in the Canmore valley and Seebe area. Our partners also supported this action, with:

- ATCO reinforcing its facility access with fencing;
- CP Rail placed effective signage and patrols; and
- the Stoney Nation Band emergency services increasing patrols and signage.

We also co-ordinated and conducted trespassing patrols in the area with Parks Canada, RCMP and bylaw officers. In addition, identified jump spots were physically taken down with our property owners in the area.

We actively monitor air emissions from our coal and gas plants. Our large coal facilities have Continuous Emissions Monitoring Systems in place, which help us monitor our pollutant emission levels to ensure they are in line with acceptable limits. When we are in breach of regulatory limits we report this to regulatory bodies and conduct a root cause analysis to understand how we can eliminate future breaches from occurring. In 2017, we had one sulphur dioxide breach at our Centralia coal plant.

Of note, our coal plants currently capture 80 per cent of mercury emissions and the majority of particulate matter emissions. Both mercury and particulate matter emissions 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 dated Nov. 19, 2015, and conducted by University of Alberta scientist Dr. Warren Kindzierski, using provincial government monitoring data over nine years, also show that 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 industry, vehicles and wood-burning fireplaces.

Assuming reasonably anticipated growth and operating scenarios, future GHG emissions and air pollution emissions performance will be dramatically reduced in respect of our existing assets in the next five years following the sale of the Solomon Power Station to FMG and as we execute our coal-to-gas conversion strategy. GHG emissions from coal will be cut within the range of 60 per cent or 12 million tonnes CO_2e. We currently capture 80 per cent of mercury emissions at our coal plants, but post-coal burn mercury emissions will be eliminated. Particulate matter and sulphur dioxide emissions will be virtually eliminated or considered negligible post-coal and diesel burn. Our nitrogen dioxide emissions will also be reduced in the range of approximately 50 per cent.

Indigenous Relationships and Partnerships
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 applicable 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. In 2017, we once again achieved the Canadian Council for Aboriginal Business's silver-level Progressive Aboriginal Relations certification. In 2016, we introduced our STAR tracking program, which functions as a communication record-keeping and engagement measurement tool. 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.

In 2017, we supported an Indigenous Leadership Program at Banff Centre for Arts and Creativity. Approximately 250 Indigenous leaders from over 120 communities attended. With help from TransAlta and other supporters, Banff Centre awarded scholarships to 191 leaders from 102 Indigenous communities across Canada, giving them the opportunity to attend this Indigenous Leadership Program.

Over the past five years, TransAlta's support has provided 39 scholarships for members of Indigenous communities to attend the programs and take that learning back to their communities. Those participants have come from communities across Alberta and British Columbia including the First Nations of Alexis Nakota Sioux, Bearspaw, Chiniki, Enoch Cree, Ermineskin Cree, Fort McKay, Kainai, Montana, Paul, Piikani, Samson Cree, Siksika, Squamish, Tsuu T'ina, and Wesley.

Stakeholder Relationships
Relationships matter to TransAlta. Driven by our values, we seek to maximize value creation for our stakeholders and TransAlta.

TransAlta Stakeholders
Our stakeholders are people. Regardless of who they represent, our goal is to act in the best interests of the Corporation and to create value across our stakeholder chain. Major stakeholder categories can be summarized as shareholders, debt holders, business partners, contractors, consultants, customers, community organizations, employees, governments, Indigenous groups, industry and professional bodies, media, NGOs, public and regulatory affairs, residents and suppliers. This too encompasses our value chain. Our mindset is value creation across this chain.

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

Methods of Engagement
In order to run our business successfully, we are in consistent two-way communication with the majority of our stakeholders, some more than others. As an example, our dialogue with customers is daily, iterative and takes on many forms including meetings (in-person, virtual, and one-one), calls, emails, newsletters and feedback systems (online loops). It is both proactive and reactive. Our approach and our goal is to be proactive, which is communicating consistent messaging and information, while being transparent. There are often times we will need to be reactive, such as to a customer complaint, and we commit to timely and professional resolution using values-based dialogue. We then work to identify how to mitigate further issues, moving back to our proactive approach.

Part of our business is growth, which we achieve by developing or purchasing new assets. We proactively engage with many stakeholders in all of our geographic operating areas in Australia, Canada and the United States in order to develop and maintain relationships; assess needs and fit; and to seek out collaborative and sustainable value creation opportunities.

Recently we completed construction of our South Hedland 150 MW combined-cycle plant in Western Australia. The project took four years from RFP to commercial operation. Achieving construction and commercial operation was the outcome of successful stakeholder engagement and collaboration. We recently announced our coal-to-gas transition plan, secured by way of collaborative stakeholder engagement. This plan involved signing a Memorandum of Understanding with the Alberta government, which highlights the project fit for Alberta, not just TransAlta. The coal-to-gas project is expected to significantly reduce the environmental impact from coal (a reduction in air pollution and GHG emissions) while enabling the transition and addition of 5,000 MW of renewable energy by 2030. We are also currently exploring the expansion of our Brazeau hydro facility, which, once again, involves the collaboration, participation and approval of many stakeholders.

More details on our stakeholder engagement activities can be found via our social media channels.

Engagement Tracking and Reporting

Our Stakeholder and Indigenous Relations tracking program functions as a Corporation-wide communication record-keeping tool, which is managed by our Stakeholder and Indigenous 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 an in-house application, this tool has no operating cost or fees and has the ability to grant different levels of access to information. Furthermore, the tool can store email conversations, documents and voice-mail messages related to any project, event, or issue, and use them in reports. It can also produce an array of statistical reports showing frequencies and volumes of engagement based on project, stakeholder, stakeholder group, issue or keywords.

Engagement and Board Communication

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 Corporation 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 the Whistleblower section of this MD&A. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. The Corporation has also adopted a Shareholder Engagement Policy that describes the Board's approach to shareholder communication. In addition, the Board has adopted an annual non-binding advisory vote on the Corporation's approach to executive compensation. The Corporation 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.

Highlights

In early 2018 we launched our new energy services for customers. Our customer solutions team has partnered with best-in-class energy service providers to help businesses achieve:

- energy consumption and energy costs management;
- market price risks and volume exposure mitigation;
- sustainability initiatives such as self-generated electricity; and
- monitoring of energy market design changes, price signals and applicable and available incentives.

Our energy services include solar, energy efficiency audits, distributed generation and building automation. To learn more, please visit the Energy Services customer page on our website.

Supply Chain

We continue to seek solutions to advance supply chain sustainability. In 2017 we partnered with Ivalua Inc. to optimize our global supply chain management operations. After an exhaustive review of all leading vendors, Ivalua was selected for its comprehensive Source-to-Pay platform, flexible architecture and overall ability to give TransAlta a competitive advantage. Key business values that we expect include increased supply chain efficiency, reduced lead times, lower costs and improved supplier performance.

We continue to offer our business units optional sustainability terms and conditions for inclusion within supplier agreements. These terms and conditions include suppliers communicating their sustainability policies, strategy and performance; documented systems for labour practices; environmental management systems; disclosure of environmental infringements; disclosure of anticompetitive behavior; disclosure on climate change management; third-party certifications on products; and demonstration of community investments. Furthermore, as we explore major projects, such as our Brazeau hydro expansion, we are assessing vendors both at the RFP evaluation stage and in up-front information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example, getting information on:

- estimated value of services that will be procured though local Indigenous businesses (in RFP template);
- estimated number of local Indigenous persons that will be employed (in RFP template);
- understanding overall community spend and engagement; and
- understanding through interview processes and stakeholder work the state of community relations.

Local Communities

TransAlta creates value for local communities through the generation of an essential service. We provide reliable, cost-efficient and clean power in Australia, Canada and the United States. With the phase-out of coal, 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, support sector jobs, and 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 to minimize disruption and negative economic impact, and to provide support for facility redevelopment, funds for retraining, and economic diversification.

Community Investments

During 2017, TransAlta contributed $2.6 million in donations and sponsorships (2016 - $2.5 million). One of our major community investments is to United Way campaigns across Canada and the US. This year, TransAlta employees, retirees, contractors and the Corporation raised over $1.28 million and directed over $0.2 million to United Way youth education programs.

In 2017, we had a focus on youth education and achieved our target to direct $0.75 million of community investment to this cause. Some of our partnerships included the University of Calgary, Southern and Northern Alberta Institutes of Technology, Mount Royal University, Banff Centre for Arts and Creativity (Indigenous leadership scholarships), Mother Earth Children's Charter School (Indigenous kindergarten to grade 9), Calgary Stampede (The Young Canadians - ages 7 to 18), national Canada and US Indigenous scholarships (post-secondary for trades and academic) and the Alberta Council for Environmental Education.

On July 30, 2015, we announced a US$55 million community investment 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.

In 2017, some highlights from grant investment included construction of an 86 kW solar project at the Tenino High School and construction of a 56 kW solar photovoltaic project for the library at Centralia College (both projects reducing power bills and CO_2 emissions). A new boiler system for the Toledo Elementary School is planned in 2018. Projects that promote a clean economy transition in Washington State will be ongoing until 2025.

Natural Capital

We continue to increase value from natural capital-related business activities, while reducing our carbon footprint. Comparable EBITDA from renewable energy generation in 2017 was $289 million (2016 - $277 million). Our revenue in 2017 from carbon-related offsets was $27.7 million (2016 - $29 million). In addition, innovation-related natural capital value creation was in the range of $25 million to $35 million, primarily from sale of coal byproducts, but also from waste related recycling.

The following are key natural capital KPI trends:

Year ended Dec. 31	2017	2016	2015
Renewable energy comparable EBITDA	**289**	277	249
Carbon offsets revenue	**27.7**	29.0	18.9
GHG emissions (million tonnes $C0_2e$)	**29.9**	30.7	32.2

Natural Capital Management

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. In 2017 we accelerated our transition from coal to gas. We are planning to convert six of our coal units to gas by 2022. We expect that by 2025 our owned asset generation capacity will be 100 per cent gas and renewables.

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-fueled 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 benefits not only our operations and financial results, but also 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 with respect to the Corporation's monitoring of environmental regulations and public policy changes and to the establishment and adherence to environmental practices, procedures and polices in response to legal/regulatory and industry compliance or best practices.

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. In 2017, 360 MW of our Alberta wind capacity was eligible to generate offsets at a rate of $20 tonne CO_2e. Annual revenue generation from these offsets was in the range of $10 million to $15 million. In 2018, as per rules associated with the new Alberta Carbon Competitiveness Incentive, our offset eligibility capacity will expand to include additional capacity from our wind fleet and hydro fleet. The price of offsets will also rise to $30/tonne CO_2e. We expect Alberta offset revenue to rise to approximately $25 million in 2018.
- Environmental controls and efficiency: We continue to make operational improvements and investments in our existing generating facilities to reduce the environmental impact of generating electricity. We have installed mercury control equipment at all of our coal operations and we achieve 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.
- 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 OCA with the Alberta Government totalling $524 million, and a Memorandum of Understanding to facilitate the conversion of coal plants to gas and the development of a capacity market.

In addition to these initiatives, we maintain procedures for environmental incidents similar to our safety practices, 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 67 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely align the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for 18 years, and our systems and knowledge of management systems are therefore mature. We no longer certify our Alberta coal plants as ISO 14001, but the plants continue to run best practice EMS. 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.

Environmental Incidents and Spills

We recorded five significant environmental incidents in 2017 (2016 - 16 incidents), which was below our target of 11. This was a record year for TransAlta and reflects our continuous improvement in tracking, presorting and identifying potential hazards. All incidents occurred at our coal fleet. None of these incidents resulted in a material environmental impact.

The following are the environmental incidents by fuel types:

Year ended Dec. 31	2017	2016	2015
Coal	**5**	13	10
Gas and renewables	**-**	3	2
Total environmental incidents	**5**	16	12

Incident types in 2017 included the expiry of an approval to transfer water, an SO_2 exceedance at our Centralia plant, a pump failure leading to an unplanned discharge and a hydrocarbon spill leading to contamination of soil and groundwater. All incidents were managed in line with our EMS practice and resolved quickly. We continue to target improvement and our corporate-wide 2018 target is nine or fewer incidents. We also continue to track and manage all non-reportable (minor) environmental incidents, which helps us identify what causes 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 estimated volume of spills in 2017 was 15 m^3 (2016 - 61 m^3).

Air Emissions

In 2017, air emissions were down compared with 2016. Air emissions decreased slightly in line with reduction in coal power generation and reduction in diesel combustion. Our future air emissions performance will be dramatically reduced in the next five years in respect of our existing assets as we execute our coal-to-gas conversion strategy and following the sale of our Solomon Power Station to FMG. We currently capture 80 per cent of mercury emissions at our coal plants, but post-coal burn mercury emissions will be eliminated following conversion. Particulate matter and sulphur dioxide emissions will be virtually eliminated or considered negligible post-coal and diesel burn. Our nitrogen dioxide emissions will also be reduced in the range of approximately 50 per cent.

Year ended Dec. 31	**2017**	2016	2015
Sulphur dioxide (tonnes)	**36,200**	39,600	41,800
Nitrogen oxide (tonnes)	**44,400**	48,400	48,000
Particulate matter (tonnes)	**5,000**	4,900	4,900
Mercury (kilograms)	**110**	130	170

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 2017 we withdrew 213 million m^3 and returned approximately 172 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	**2017**	2016	2015
Water from environment	**213**	239	258
Water to environment	**172**	197	212
Total water consumption	**41**	42	46

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 a greater 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. Our Centralia mine in Washington State is currently in the reclamation phase (35 per cent reclaimed), and our Highvale mine in Alberta is actively mined with certain sections undergoing reclamation. Our reclamation plans are set out on a life-cycle basis and include contouring disturbed areas, re-establishing 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 2017, we reclaimed 57 acres (23 hectares) at our Highvale mine, which was below our target of 74 acres (30 hectares). This was due to competing priorities for equipment and inclement weather (early thaw and rain), which limited the opportunities to meet the topsoil placement goal. The Centralia mine is no longer actively used for coal operations, but reclamation activity is ongoing. In 2017, we reclaimed 16 hectares of land. Our Centralia mine team added another 150,000 Douglas Fir during the 2017 planting season, bringing the number of trees planted since 1991 to over 1.8 million.

In 2016, we decommissioned our Cowley Ridge wind plant, which was Canada's first commercial wind plant constructed in 1993 and reached its end of life in 2016. During this process, our wind operations team recycled:

- 54 towers weighing 20,000 pounds;
- 61 nacelles — the housing of the turbine generating components — weighing 22,000 pounds;
- 19 transformers weighing 9,000 pounds; and
- 32,000 litres of oil.

Our recycling efforts meant that we diverted 2,609,000 pounds from the land fill. This job was completed safely, and in addition generated around $0.15 million of value from the recycled components. This work reflects TransAlta's values of innovation and safety, while maintaining a positive environmental impact at our operations.

In 2015, we donated 64 acres of land to the Alberta Fish & Game Association Wildlife Trust Fund. The land includes an area that was once a mine settling pond and is now 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.

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 use the sun 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.

As an energy corporation, we naturally look for ways to optimize or create efficiencies related to the use of energy. Our coal-to-gas conversions display one innovative way we intend to reduce a significant amount of energy use and significantly reduce our environmental impact, while returning the generation of reliable and low-cost power supply to Albertan customers.

The following captures our energy use (millions of gigajoules). 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 (in millions of GJ)	**2017**	2016	2015
Coal	**447.4**	469.1	483.4
Gas and renewables	**49.4**	59.2	58.9
Corporate	**0.1**	0.1	0.1
Total energy use	**496.9**	528.4	542.4

Greenhouse Gas Emissions
In 2017, we estimate that 29.9 million tonnes of GHGs with an intensity of 0.86 tonnes per MWh (2016-30.7 million tonnes of GHGs with an intensity of 0.83 tonnes per MWh) were emitted as a result of normal operating activities.(1) Our GHG emissions decreased in 2017, primarily as a result of lower emissions from our gas facilities. In 2017 our Mississauga plant was no longer operational and our Windsor plant transitioned to a peaking facility. In Australia, our diesel burn at Parkeston and Solomon Power Station significantly declined. Our coal GHG emissions were relatively flat overall. At our Centralia plant in Washington State production increased due to market demand, which increased our emissions from the facility by 1.4 million tonnes of CO_2e. This was offset by lower production and associated emissions (-1.6 million tonnes of CO_2e) from our Alberta coal fleet.

The following are our GHG emissions in million tonnes CO_2:

Year ended Dec. 31 (in million tonnes $C0_2$)	2017	2016	2015
Coal	**27.4**	27.7	29.2
Gas and renewables	**2.5**	3.0	3.0
Total GHG emissions	**29.9**	30.7	32.2

Our total GHG emissions include both scope 1 and scope 2 emissions(2). Scope 1 emissions in 2017 were estimated to be 29.7 million tonnes CO_2e. Scope 2 emissions were estimated to be 0.2 million tonnes CO_2e. We estimate our scope 3 emissions to be in the range of six million tonnes.

In 2017, TransAlta maintained its scoring on the Carbon Disclosure Project Climate Change investor request. Our overall score was a B, which places us as ahead of our peers when it comes to carbon disclosure, management, performance and leadership. We were also highlighted by the Chartered Professional Accountants of Canada ("CPA 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. Our 2016 Integrated Report was selected as a finalist for CPA Canada's Award of Excellence in Corporate Reporting – of note, our Climate Change disclosure was highlighted as "outstanding" by CPA Canada Judges.

Climate Change
We believe in open and transparent reporting on climate change. Our climate change reporting is guided by the Financial Stability Board Task Force on Climate Related Financial Disclosures recommendations. The following highlights our management of climate change related impacts. For more detailed information, please visit our Climate Disclosure webpage: https://www.transalta.com/sustainability/climate-change-action-and-strategy/

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(1) 2017 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO_2, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO_2 emissions from stationary combustion. Emissions intensity data has been aligned with the "Setting Organizational Boundaries: Operational Control" methodology set out in The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. As per the methodology, TransAlta reports emissions on an operation control basis, which means that 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.

(2) The GHG Protocol Corporate Standard classifies a company's GHG emissions into three 'scopes'. Scope 1 emissions are direct emissions from owned or controlled sources. Scope 2 emissions are indirect emissions from the generation of purchased energy. Scope 3 emissions are all indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.

Climate change related risks are monitored through our Corporation-wide risk management processes and actively managed. Identified climate change risks and opportunities are also reviewed by our management team. We apply 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 our facilities. It is also a method of modelling for future electricity prices and analyzing 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 offset portfolios to achieve emissions reductions at competitive costs;
- development of clean combustion technologies; and
- 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. 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 goals for undertaking such anticipated actions are to enhance 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 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 power in Alberta. Production from renewable energy in 2017 resulted in avoidance of over 3.1 million tonnes of CO_2e, which is equivalent to removing over 660,000 vehicles from North American roads over the same year. For further details on governance and risk, see the Governance and Risk Management section of this MD&A.

Climate change related risks are monitored through our Corporation-wide risk management processes and actively managed. Identified climate change risks and opportunities are identified at the business unit level and through corporate functions (government relations, regulatory, emissions trading, and sustainability). Risks and opportunities are reviewed by our management team quarterly and reported to the Governance Environment and Safety Committee ("GESC") of the Board and the Audit and Risk Committee of the Board, as applicable.

Risk or opportunity	Management approach
Policy requirements	TransAlta supports smart regulation and carbon pricing that ensures economic growth and certainty for investment. We have also demonstrated co-operation and collaboration on climate-related policy, while ensuring we protect value for employees and shareholders. This is evidenced by our Off-Coal Agreement with the Alberta Government, totalling $524 million and Memorandum of Understanding to convert coal plants to gas. Further climate-related policy updates can be found in the Regional Regulation and Compliance subsection of this MD&A
Carbon pricing	Our corporate function attributes 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. This information is directed to the business unit level for further integration. Identified climate change risks or opportunities and carbon pricing are recognized in the annual TransAlta long-and-medium range forecasting processes. We capture economic profit from carbon markets through generation of renewable energy credits or offsets and via our emission trading function, which seeks to commoditize and profit from carbon trading.
New technology	We have demonstrated upside in growing renewable and gas power generation. From 2000 to 2017 we have grown renewable capacity from approximately 900 MW to over 2,200 MW. Our proposed Brazeau hydro expansion is an innovative energy storage project, which would involve a 900 MW expansion of the facility to operate as a pumped hydro facility.
Adaptation and mitigation	Our clean power strategy means that all new investment must meet clean standards in order to mitigate potential future risk related to carbon policy and pricing. Our target is for 100 per cent of net generation capacity to be from gas and renewables capacity by 2025. Our coal-to-gas conversion plan in Alberta is an adaptive measure to climate change related policy. Using existing infrastructure significantly reduces capital costs compared with new gas builds and also results in the avoidance of approximately $15/MW in carbon related pricing (assuming a $30 per tonne carbon price). Our new gas facility at South Hedland Power Station is built with adaptation in mind. The facility will operate with a best-in-class emission intensity, and the facility uses less water than traditional gas plants as we use dry cooling towers as opposed to the normal wet cooling towers (wet cooling tower have heavy water consumption). The plant is designed to withstand a category 5 cyclone, which can frequent the northwest region of Western Australia. Category 5 is the highest cyclone rating. Floods, which can occur in the area, have been mitigated by constructing the facility above the normal flood levels.
Water stress	Our thermal plants require water for operation. The majority of our thermal facilities are operated in low water stress environments. Our most water-stressed area of operation is at Sarnia; however, due to the nature of the operation, 98 per cent of water is recycled. The plant is a cogeneration facility. At all of our coal facilities we hold licences to pull water from low stressed areas. In Australia we purchase water for operations, and despite operating in remote locations, these areas are not currently water-stressed. Water purchasing will allow us to minimize local water stress if this becomes an issue. Our operating cost increase exposure due to water in Australia is low as our thermal operations are small.

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 five 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 and mothballing of Sundance Units 1 and 2, respectively, 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 using 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.

Adaptation

Our new South Hedland gas facility in Western Australia started commercial operation in 2017. The facility is built with adaptation in mind. The facility will operate with a best-in-class emission intensity for gas power generation and the facility uses less water than traditional gas plants as we use dry cooling towers as opposed to the normal wet cooling towers (wet cooling towers have heavy water consumption). The plant is designed to withstand a category 5 cyclone, which can frequent this region. Category 5 is the highest cyclone rating. The plant was also constructed above normal flood levels, as floods can occur in the area.

In 2017, our wind operations team developed and implemented a Blade Icing Mitigation program designed to reduce downtime of wind turbines during icing events. The program entails weather forecasting data, revised standard procedures and alarms for both active and forecasted icing conditions. Created for our wind farms in Ontario, Quebec and New Brunswick, this program allows our technicians to analyze the data before an icing event occurs and reduce the time during which the wind turbines are shut down, in turn increasing the generating time, revenue opportunity and safety of the wind turbines. Typically, we lose 40,000 MWh annually due to icing events. In 2017, we set a goal to reduce this by 5 per cent or $0.25 million. In its first season, the program has saved over $0.6 million. This program will be extremely valuable to ongoing operations of the wind turbines during the winter months.

Regional Regulation and Compliance

Carbon pricing 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 decisions changed the coal plant closure requirements, which had previously been guided by federal regulations that became effective on July 1, 2015, and that provided for up to 50 years of life for coal units. According to the new shutdown 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 develop 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 conducted 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 are currently assessing how this price mechanism will affect our operations.

Alberta

On Nov. 22, 2015, the Government of Alberta announced, through the CLP, its intent 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 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 developing 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 framework for its application to fuels. It was effective for the electricity sector on Jan. 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, to facilitate existing and new renewable electricity development through supportive and enabling policy, and to ensure existing generation and new electricity generation are able to effectively participate in the capacity market being developed for the Province of Alberta.

On Jan. 1, 2018, the Alberta government transitioned from Specified Gas Emitters Regulation ("SGER") to the Carbon Competitiveness Incentive Regulation ("CCIR"). Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product/sectoral performance compliance standard. The carbon price remains set at $30/tCO$_2$e from 2018 to 2022 and will then follow the federal price increase to $40/tCO$_2$e in 2021 and $50/tCO$_2$e in 2022. The electricity sector performance standard was set at 0.37tCO$_2$e/MWh but will decline over time. All renewable assets that received crediting under the SGER will continue to receive credits under CCIR on a one-to-one basis. All other renewable assets that did not receive credits under SGER will now be able to opt into the CCIR and get carbon crediting up to the electricity sector performance standard in perpetuity. Once the wind projects crediting standard under SGER ends, these renewable projects will also be able to opt into the CCIR and receive crediting.

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, which in most cases is 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. This is 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 solicited interest in the first competitive procurement for 400 MW in 2017. Eligible projects must be 5 MW or larger and can be hydro, wind, solar and certain biomass. The first competition utilized an indexed renewable energy credit or contract for difference mechanism that will fix the price to the proponent for over 20 years. Four successful projects were announced in December of 2017, for nearly 600 MW of wind generation at a weighted average bid price of $37/MWh.

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 reliance on scarcity pricing, which drives energy price volatility and the price signal for new investment, and to compensate resource owners with monthly capacity payments for making their capacity available in the energy and ancillary services market. The AESO is currently engaging with stakeholders in determining the design and implementation of the capacity market. The AESO will begin formalizing the capacity market design and implementing it in the second half of 2018, with the first procurement expected in the second half of 2019, to be effective in 2021, with first capacity contracts awarded at that time.

Pacific Northwest

Our Centralia coal facility is located in Washington State. On Dec. 17, 2014, Washington State Governor Jay Inslee released a carbon-emissions reduction program for the state. Included in that program were a cap-and-trade plan and a low-carbon fuels standard, with the proposed emissions cap becoming more stringent over time, providing emitters time to transition their operations. A late-2017 Court of Appeals case found that the Governor's Clean Air Rule was beyond his authority to implement.

On Aug. 3, 2015, the US federal government announced the Clean Power Plan ("CPP"). The plan set out GHG emission standards for new fossil-fuel-based power plants and emission limits for individual states. States had the option of interpreting their limits in mass-based (tons) or rate-based (pounds per MWh) terms. The plan was intended to achieve an overall reduction in GHG emissions of 32 per cent from 2005 levels by 2030. On Feb. 9, 2016, the US Supreme Court stayed the implementation of the Clean Power Plan, pending consideration of whether the regulations are lawful. Currently, the Environmental Protection Agency ("EPA') is not expected to implement the CPP, although the EPA will still have an obligation to address climate change emissions. The EPA's new approach to addressing climate change has yet to be defined or consulted on. The US also provided notice of its intention to withdraw from the 2015 Paris Agreement.

TransAlta has agreed with Washington State to retire its two Centralia coal units in 2020 and 2025 respectively. 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 US Coal given these commitments. The related TransAlta Energy Transition Bill was signed into law in 2011 and provides a framework to transition from coal to other forms of generation in the State. We are currently evaluating a number of transition solutions.

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 PPAs.

Australia

In March 2017, state elections were held in Western Australia and a change of government took place. The new Labor government announced a road map for electricity initiatives. The reform program focuses on three pillars of work: improving access to Western Power's network, improving reserve capacity and pricing signals, and improving access to, and operation of, the Pilbara electricity network.

Coal Transition

Our coal transition, whether it is executing on our coal-to-gas conversion plans or completing a full phase-out by 2030, is expected to vastly improve our environmental performance. Energy use, GHG, air emissions, waste generation and water usage is expected to 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.

2017 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 in the sustainability section of our website.

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.

2017 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 out of four rating agencies: S&P (BBB-) negative outlook, DBRS (BBB low) stable outlook, and Fitch (BBB-) stable outlook
2. Increase focus on FFO(1) and EBITDA(1)	Deliver comparable EBITDA and FFO in the range of $1,025 million to $1,135 million and $765 million to $855 million respectively	Achieved	For the year ended Dec. 31, 2017, comparable EBITDA was $1,062 million and FFO was reported at $804 million

(1) Represents our original outlook. In the second quarter we reduced the following 2017 targets: Comparable EBITDA from the previously announced target range of $1,025 million to $1,135 million to $1,025 to $1,100 million, FFO from the previously announced target range of $765 million to $855 million to $765 million to $820 million FCF target range to $270 million to $310 million from the previously announced target range of $300 million to $365 million.

	Human and Intellectual	Results	Comments
3. Reduce safety incidents	Achieve an Injury Frequency Rate below 0.50	Not achieved	Although we missed our target, we achieved one of our lowest IFRs in our history. Our 2017 IFR was 0.72, a 15 per cent improvement over 2016 performance
4. Human Resources	Maintain voluntary turnover percentage under eight per cent	Not achieved	Our voluntary turnover in 2017 was 11 per cent. We seek to maintain voluntary turnover or attrition under eight per cent as this is considered a healthy amount of attrition for a corporation. As we transition away from coal-fired generation and its associated jobs we face significant workforce challenges with retention. The lack of job security and uncertainty is unsettling for many of our coal employees and we faced this challenge in 2017
5. Support employee development	Continue development plans for all high-potential employees at the top three levels of the organization	Achieved	In 2017, we completed a six-month (intermittent) leadership training program, called Elevate, for our middle management. This resulted in the training of approximately 75 leaders in our company. The program was focused on establishing a learner's mindset, building trust and influence, strengths-based leadership, being transparent, providing feedback, collaboration as a team and innovation

	Natural	Results	Comments
6. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 11	Achieved	We recorded 5 signficant environmental incidents in 2017, none of which had a material environmental impact. This was a 54 per cent improvement over 2016 performance
7. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 74 acres/year	Partly achieved	We were able to replace 57 acres in 2017. Competing priorities for equipment and inclement weather (early thaw and rain) limited the opportunities to meet the topsoil placement goal
8. Utilize coal by-product	Sell a minimum of two million tonnes of coal byproduct materials during the period 2015 to 2017	Achieved	We reused and sold over 2 million tonnes of coal byproducts (fly ash, bottom ash, cenospheres and gypsum) from 2015 to 2017
9. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO_2 emissions by 2030	On track	We reduced levels of NO_x and SO_2 in 2017 by close to 4,000 tonnnes collectively and remain on track to realize these emission reductions by 2030
10. Reduce GHG emissions	a) 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	On track	We reduced GHG emissions in 2017 by close to 1 million tonnes and we remain on track to realize emission reductions by 2021/2030
	b) 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	On track	

	Social and Relationship	Results	Comments
11. Support youth education with community investment	Approximately $0.75 million of community investment spending will be directed to supporting youth education	Achieved	Some of our partnerships included the University of Calgary, Southern and Northern Alberta Institute of Technology, Mount Royal University, Banff Centre for Arts and Creativity (Indigenous leadership scholarships), Mother Earth Children's Charter School (Indigenous kindergarten to grade 9), Calgary Stampede (The Young Canadians - ages 7 to 18), national Canada and US Indigenous scholarships (post-secondary for trades and academic) and the Alberta Council for Environmental Education
12. 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	Achieved	An Indigenous Awareness presentation was developed, which includes historical facts and basic concepts around consultation and engagement, which will be shared with all employees. The same presentation will be used at the Schulich School of Engineering at the University of Calgary in 2018 for one of their ethics courses

	Comprehensive	Results	Comments
13. 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	Achieved	We signed a Memorandum of Understanding with the Alberta Government in 2016 to advance coal to gas conversions, expand credits for existing renewable energy facilities and level the playing field for incumbents from a capacity market. We also signed an OCA with the Alberta Government totaling $524 million of compensation to the Corporation

2018 Sustainable Development Targets

Our 2018 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 0.53	20 per cent improvement over 2017 performance (0.75)
	Achieve a Total Incident Frequency rate below 2.83	New target
2. Manage employee turnover	Maintain voluntary turnover percentage under eight per cent	Consistent with 2017 target, we seek to maintain voluntary turnover under 8 per cent as this is considered a healthy amount of turnover
3. Support employee development	Advance our Elevate leadership training, completing training for 75 professionals or subject matter experts	Builds upon 2017 target and our continued focus on employee development

	Natural	Annual Performance Status
4. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below 9	20 per cent improvement over 2017 target
5. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 70 acres/year	Below 2017 target (74 acres)
6. Reduce air emissions	95 per cent reduction from 2005 levels of TransAlta coal facility NO_x and SO_2 emissions by 2030	Consistent with 2017 (long-term target)
7. 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 (Our GHG and clean power targets assume reasonably anticipated growth and operating scenarios)	
	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 (Our GHG and clean power targets assume reasonably anticipated growth and operating scenarios)	Consistent with 2017 (long-term target)

	Social and Relationship	Annual Performance Status
8. Support quality education for youth	Support equal access to all levels of education for youth and Indigenous peoples	New target
Our education goal and targets support UN SDG *Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"*	Approximately $0.75 million of community investment spending will be directed to supporting youth education	Consistent with 2017 target
9. Increase internal best practice Aboriginal engagement awareness	Develop sustainability and indigenous engagement materials for Integration within our developmental leadership programs at TransAlta	New target

	Comprehensive	Annual Performance Status
10. TransAlta will be a leading clean power company by 2030	By 2022, we will convert six coal plant units from coal-fired generation to gas-fired generation	New target
Our clean power goal and targets support the UN SDG Goal 7: Affordable and Clean Energy related to ensuring "access to affordable, reliable, sustainable and modern energy"	By 2025, 100 per cent of our owned asset company-wide net generation capacity will be from gas and renewables	New target
	We will continue to seek new opportunities to grow our portfolio of 2,265 MW wind, hydro and solar assets	New target
	Continue to explore viability of Brazeau 900 MW pumped hydro expansion – doubling our hydro capacity in Alberta	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 is responsible for overseeing the management of the Corporation by establishing key policies and standards, including policies for the 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 GESC, 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 GESC 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 GESC is also responsible for Board recruitment and for the nomination of directors to the Board and its committees. In addition, the GESC 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 GESC 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 GESC 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 Legal and Compliance Officer and Corporate Secretary 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 US 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, 2017, associated with our proprietary commodity risk management activities was $5 million (2016 - $2 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 2017. 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	12

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 2017, we had approximately 92 per cent (2016 - 88 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 2017, 57 per cent (2016 - 79 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2016 - 100 per cent) of our purchased coal costs were contractually fixed.

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 US 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 US 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 US 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 US 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 CLP) and the US 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 US to advocate that regulatory changes are well designed and cost effective;
- developing compliance plans that address how to meet or surpass emission standards for GHGs, mercury, SO_2, and NOx, which will be adjusted as regulations are finalized;
- purchasing emission reduction offsets;
- investing in renewable energy projects, such as wind, solar, and hydro generation,;and
- incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

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

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, 2016. We had no material counterparty losses in 2017. 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, 2017:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	87	13	**100**	**933**
Long-term finance lease receivables	96	4	**100**	**215**
Risk management assets[1]	-	100	**100**	**899**
Loan receivable[2]	-	100	**100**	**33**
Total				**2,080**

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 $40 million (2016 - $14 million).

Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the cash flows from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our US denominated debt. Our exposures are primarily to the US and Australian currencies. Changes in the values of these currencies in relation to the Canadian dollar may affect our cash flows 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 US operations using US-denominated debt;
- entering into forward foreign exchange contracts to hedge future foreign denominated expenditures including our US-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 US-dollar-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 US or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter, and is shown below:

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Counterparty has no external credit rating. Excludes $5 million current portion classified in trade and receivables.

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, 2017, we have liquidity of $1.6 billion comprised of amounts not drawn under our committed credit facilities and cash on hand.

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, 2017, approximately six per cent (2016 - six 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 before starting 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 2017, 52 per cent (2016 - 53 per cent) of our labour force was covered by 11 (2016 - 11) collective bargaining agreements. In 2017, four (2015 - five) agreements were renegotiated. We anticipate the successful negotiation of four collective agreements in 2018.

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 CLP 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 the 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.

Cybersecurity Risk

We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. Cyberattacks or other breaches of network or information technology systems security may cause disruptions to our operations. Cyberattackers may use a range of techniques, from manipulating people to using sophisticated malicious software and hardware on a single or distributed basis. Some cyberattackers 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 cyberattacks that may damage our infrastructure, systems and data. Our cybersecurity 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 facilities 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.

On Dec. 22, 2017, the US government enacted H.R.1, originally known as the *Tax Cuts and Jobs Act*, which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income.

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

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

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.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2017	2016
Revenues	**638**	717
Net earnings (loss) attributable to common shareholders	**(145)**	61
Cash flow from operating activities	**81**	122
Comparable EBITDA(1)	**275**	374
FFO(1)	**219**	200
FCF(1)	**101**	62
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.50)**	0.21
FFO per share(1)	**0.76**	0.69
FCF per share(1)	**0.35**	0.22
Dividends declared per common share	**0.04**	0.08

Financial Highlights

We delivered better than anticipated results in the fourth quarter with FCF of $101 million, up $39 million over the same period last year. We recorded FFO of $219 million, up $19 million over the fourth quarter of 2016, as the business delivered a solid performance.

Net loss attributable to common shareholders in the fourth quarter of 2017 was $145 million ($0.50 net loss per share) compared to net earnings of $61 million ($0.21 net earnings per share) in the same period of 2016, down over $200 million compared to last year. This was driven by lower comparable EBITDA ($101 million pre-tax) and the impact of the US tax rate reduction ($105 million). Last year, net earnings also included a one-time gain of $48 million (net of related income tax expense and non-controlling interest) for the Mississauga recontracting.

Segmented Cash Flows Generated by the Business and Operational Performance(1)

Segmented Cash Flows and operational performance for the business during the quarter is as follows:

Three months ended Dec. 31	2017	2016
Availability (%)(2)	**88.4**	88.9
Adjusted availability (%)(3)	**88.4**	88.9
Production (GWh)(2)	**10,374**	10,624
Segmented cash inflow (outflow)		
Canadian Coal	**11**	36
US Coal	**15**	16
Canadian Gas	**56**	75
Australian Gas	**27**	24
Wind and Solar	**73**	64
Hydro	**10**	9
Generation cash inflow	**192**	224
Energy Marketing	**15**	(11)
Corporate	**(28)**	(28)
Total comparable cash inflow	**179**	185

(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) 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.

(3) Adjusted for economic dispatching at US Coal.

Segmented cash flows generated by the business measures the net cash generated by each of our segments after sustaining and productivity capital expenditures, reclamation costs and provisions. It also excludes non-cash mark-to-market gains or losses. This is the cash flows available to pay our interest and cash taxes, distributions to our non-controlling partners and dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

Adjusted availability for the three months ended Dec. 31, 2017, was comparable with the same period in 2016.

Lower production for the three months ended Dec. 31, 2017, compared to the same period in 2016, is primarily due to higher outages and derates at our Canadian Coal segment, the Mississauga recontracting in 2016, and lower resources at Hydro, partially offset with lower economic dispatching caused by higher price at our US Coal business, stronger wind resources in Canada, and the commissioning of the South Hedland Power Station in the third quarter of 2017.

Cash flows generated by the business totalled $179 million in the fourth quarter, in line with last year's performance.

Discussion of Consolidated Financial Results

We evaluate our performance and the performance of our business segments using a variety of measures. Comparable figures are not defined under IFRS. Those discussed below, and elsewhere in this MD&A, are not defined under IFRS and, therefore, should not be considered in isolation or as an alternative to or to be more meaningful than net earnings attributable to common shareholders or cash flow from operating activities, as determined in accordance with IFRS, when assessing our financial performance or liquidity. These measures are not necessarily comparable to a similarly titled measure of another company. Each business segment assumes responsibility for its operating results measured to comparable EBITDA and cash flows generated by the business. Gross margin is also a useful measure as it provides management and investors with a measurement of operating performance that is readily comparable from period to period.

Comparable EBITDA

A reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA results is set out below:

Three months ended Dec. 31	2017	2016
Net earnings (loss) attributable to common shareholders	**(145)**	61
Net earnings attributable to non-controlling interests	**19**	90
Preferred share dividends	**10**	20
Net earnings (loss)	**(116)**	171
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**105**	82
Gain on sale of assets and other	**(1)**	(3)
Foreign exchange (gain) loss	**(6)**	3
Net interest expense	**57**	47
Depreciation and amortization	**180**	187
Comparable reclassifications		
Decrease in finance lease receivables	**15**	15
Mine depreciation included in fuel cost	**20**	19
Australian interest income	**1**	-
Adjustments to earnings to arrive at comparable results		
Impacts to revenue associated with certain de-designated and economic hedges	**-**	2
Impacts associated with Mississauga recontracting(1)	**20**	(177)
Asset impairment charge	**-**	28
Comparable EBITDA	**275**	374

A summary of our comparable EBITDA by segments for the three months ended Dec. 31, 2017 and 2016 is as follows:

Three months ended Dec. 31	2017	2016
Comparable EBITDA		
Canadian Coal	**66**	178
US Coal	**21**	14
Canadian Gas	**62**	70
Australian Gas	**29**	32
Wind and Solar	**78**	66
Hydro	**14**	20
Energy Marketing	**25**	13
Corporate	**(20)**	(19)
Total comparable EBITDA	**275**	374

Comparable EBITDA decreased by $99 million for the fourth quarter 2017, compared to 2016. Our Canadian Coal results were down $112 million mainly due to the inclusion of the $80 million reversal of the Keephills 1 provision in 2016, higher coal costs caused by a higher strip ratio and lower equipment availability at our mine, and higher environmental compliance costs in 2017. This was partly offset by the OCA payments. Lower prices due to the rolling off of certain hedges also negatively impacted Canadian Coal's results. Energy Marketing's comparable EBITDA was up $12 million during the fourth quarter of 2017 compared to 2016 due to a return to a normalized level and solid performance in Alberta and Western US. Wind and Solar generated an increase of $12 million comparable EBITDA period-over-period mainly due to higher volumes at contracted facilities and lower cost of sales from renewable energy certificates. Our Canadian Gas business was down $8 million period-over-period due to unfavourable mark-to-market in gas contracts that do not qualify for hedge accounting. Lower resources at certain hydro facilities resulted in lower comparable EBITDA by $6 million period-over-period.

(1) Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2017, are as follows: revenue ($29 million) and recovery related to renegotiated land lease ($9 million). Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2016, are as follows: net other operating income ($191 million) and fuel and purchased power and de-designated hedges ($14 million).

Funds from Operations and Free Cash Flow

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

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

Three months ended Dec. 31	2017	2016
Cash flow from operating activities	81	122
Change in non-cash operating working capital balances	121	61
Cash flow from operations before changes in working capital	202	183
Adjustments:		
Decrease in finance lease receivable	15	15
Other	2	2
FFO	219	200
Deduct:		
Sustaining capital	(62)	(85)
Productivity capital	(9)	(2)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(36)	(40)
Other	(1)	(1)
FCF	101	62
Weighted average number of common shares outstanding in the period	288	288
FFO per share	0.76	0.69
FCF per share	0.35	0.22

FFO was up $19 million during the fourth quarter of 2017 compared to the same period in 2016. FCF increased by $39 million period-over-period as we continued to reduce our sustaining capital resulting from our announcement in April 2017 to mothball certain Sundance units.

The table below bridges our comparable EBITDA to our FFO and FCF.

Three months ended Dec. 31	2017	2016
Comparable EBITDA	275	374
Provisions	(10)	(104)
Unrealized (gains) losses from risk management activities	(8)	16
Interest expense	(52)	(52)
Current income tax expense	(6)	(6)
Decommissioning and restoration costs settled	(7)	(8)
Realized foreign exchange gain (loss)	8	(3)
Other	19	(17)
FFO	219	200
Deduct:		
Sustaining capital	(62)	(85)
Productivity capital	(9)	(2)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(36)	(40)
Other	(1)	(1)
FCF	101	62
Weighted average number of common shares outstanding in the period	288	288
FFO per share	0.76	0.69
FCF per share	0.35	0.22

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 US 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 2017	Q2 2017	Q3 2017	**Q4 2017**
Revenues	578	503	588	**638**
Comparable EBITDA	274	268	245	**275**
FFO	202	187	196	**219**
Net loss attributable to common shareholders	-	(18)	(27)	**(145)**
Net loss per share attributable to common shareholders, basic and diluted(1)	-	(0.06)	(0.09)	**(0.50)**

	Q1 2016	Q2 2016	Q3 2016	Q4 2016
Revenues	568	492	620	717
Comparable EBITDA	279	248	243	374
FFO	196	175	163	228
Net earnings (loss) attributable to common shareholders	62	6	(12)	61
Net earnings (loss) per share attributable to common shareholders, basic and diluted(1)	0.22	0.02	(0.04)	0.21

(1) Basic and diluted earnings per share attributable to common shareholders and comparable earnings per share are calculated each period using the weighted average number of 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.

Reported net earnings, comparable EBITDA and 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;
- US 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 third quarter of 2015, and the first and second quarters of 2016, and the second quarter of 2017;
- change in income tax rates in Alberta and the U.S. in the second quarter of 2015, and fourth quarter of 2017, respectively;
- 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, and unrealized gains in the first quarter of 2017;
- effects of the Keephills 1 outage provision in the fourth quarter of 2016;
- effects of the Wintering Hills impairment charge during the fourth quarter of 2016, and the Sundance Unit 1 impairment charge during the second quarter of 2017;
- effects of the Mississauga facility recontracting during the fourth quarter of 2016;
- effects of changes in useful lives of certain Canadian Coal assets during the first, second, and third quarters of 2017; and
- effects of an impairment of $137 million in 2017 on intercompany financial instruments that is attributable only to the non-controlling interests.

Disclosure Controls and Procedures

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

There have been no other changes in our internal control over financial reporting during the year ended Dec. 31, 2017, 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, 2017, the end of the period covered by this report, our disclosure controls and procedures were effective.

Consolidated Financial Statements

Management's Report

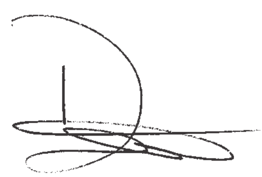
To the Shareholders of TransAlta Corporation

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 1, 2018

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. 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 2017 consolidated financial statements of TransAlta included $624 million and $550 million of total and net assets, respectively, as of December 31, 2017, and $160 million and $9 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, 2017, 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, 2017, 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 1, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

Opinions on the Internal Control over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2017, 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"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position as at December 31, 2017 and 2016, 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, 2017 of TransAlta Corporation and our report dated March 1, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

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 TransAlta Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the TransAlta Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standard of the PCAOB. The standards of the PCAOB 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.

Definition and Limitations of Internal Control over Financial Reporting

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 International Financial Reporting Standards by the International Accounting Standards Boards. 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 International Financial Reporting Standards as issued by the International Accounting Standards Board, 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 2017 consolidated financial statements of TransAlta Corporation and constituted $624 million and $550 million of total and net assets, respectively, as of December 31, 2017, and $160 million and $9 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 1, 2018

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of TransAlta Corporation , which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, and the consolidated statements of earnings (loss), consolidated statements of comprehensive income (loss), consolidated statements of changes in equity and consolidated statements of cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements").

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransAlta Corporation as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the three years ended December 31, 2017, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and our report dated March 1, 2018 expressed an unqualified opinion on the effectiveness of TransAlta Corporation's internal control over financial reporting.

Basis for Opinion

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 PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to TransAlta Corporation in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our 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, we consider internal control relevant to the TransAlta Corporation'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 evaluating the appropriateness of accounting policies and principles 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 reasonable basis for our audit opinion.

We have served as the Corporation's auditor since 1947.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada

March 1, 2018

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2017**	2016	2015
Revenues *(Note 33)*	**2,307**	2,397	2,267
Fuel and purchased power *(Note 5)*	**1,016**	963	1,008
Gross margin	**1,291**	1,434	1,259
Operations, maintenance, and administration *(Note 5)*	**517**	489	492
Depreciation and amortization	**635**	601	545
Asset impairment charges (reversals) *(Note 6)*	**20**	28	(2)
Restructuring provision *(Note 4)*	**—**	1	22
Taxes, other than income taxes	**30**	31	29
Net other operating (income) losses *(Note 8)*	**(49)**	(194)	25
Operating income	**138**	478	148
Finance lease income *(Note 7)*	**54**	66	58
Net interest expense *(Note 9)*	**(247)**	(229)	(251)
Foreign exchange gain (loss)	**(1)**	(5)	4
Gain on sale of assets and other *(Note 4)*	**2**	4	262
Earnings (loss) before income taxes	**(54)**	314	221
Income tax expense *(Note 10)*	**64**	38	105
Net earnings (loss)	**(118)**	276	116
Net earnings (loss) attributable to:			
TransAlta shareholders	**(160)**	169	22
Non-controlling interests *(Note 11)*	**42**	107	94
	(118)	276	116
Net earnings (loss) attributable to TransAlta shareholders	**(160)**	169	22
Preferred share dividends *(Note 24)*	**30**	52	46
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Weighted average number of common shares outstanding in the year *(millions)*	**288**	288	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted *(Note 23)*	**(0.66)**	0.41	(0.09)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2017**	2016	2015
Net earnings (loss)	**(118)**	276	116
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**(6)**	8	4
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(2)]	**(1)**	(1)	3
Total items that will not be reclassified subsequently to net earnings	**(7)**	7	7
Gains (losses) on translating net assets of foreign operations, net of tax[(3)]	**(80)**	(71)	247
Reclassification of translation gains on net assets of divested foreign operations[(4)] *(Note 4)*	**(9)**	—	(10)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(5)]	**50**	18	(172)
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[(6)] *(Note 4)*	**14**	—	6
Gains on derivatives designated as cash flow hedges, net of tax[(7)]	**214**	179	375
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(8)]	**(107)**	(48)	(194)
Total items that will be reclassified subsequently to net earnings	**82**	78	252
Other comprehensive income	**75**	85	259
Total comprehensive income (loss)	**(43)**	361	375

Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(74)**	215	272
Non-controlling interests *(Note 11)*	**31**	146	103
	(43)	361	375

(1) Net of income tax recovery of 4 for the year ended Dec. 31, 2017 (2016 - 4 expense, 2015 - nil).
(2) Net of income tax expense of nil for the year ended Dec. 31, 2017 (2016 - nil , 2015 - 1 expense).
(3) Net of income tax expense of nil for the year ended Dec. 31, 2017 (2016 - 11, 2015 - nil).
(4) Net of reclassification of income tax expense of 11 for the year ended Dec. 31, 2017 (2016 - nil, 2015 - nil).
(5) Net of income tax expense of 2 for the year ended Dec. 31, 2017 (2016 - 5 expense, 2015 - 7 expense).
(6) Net of reclassification of income tax recovery of 2 for the year ended Dec. 31, 2017 (2016 - nil recovery, 2015 - 1 recovery).
(7) Net of income tax recovery of 77 for the year ended Dec. 31, 2017 (2016 - 92 expense, 2015 - 138 expense).
(8) Net of reclassification of income tax expense of 31 for the year ended Dec. 31, 2017 (2016 - 41 expense, 2015 - 50 expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2017**	2016
Cash and cash equivalents	**314**	305
Trade and other receivables *(Note 12)*	**933**	703
Prepaid expenses	**24**	23
Risk management assets *(Notes 13 and 14)*	**219**	249
Inventory *(Note 15)*	**219**	213
Assets held for sale *(Note 4)*	**—**	61
	1,709	1,554
Restricted cash *(Note 21)*	**30**	—
Long-term portion of finance lease receivables *(Note 7)*	**215**	719
Property, plant, and equipment *(Note 16)*		
Cost	**12,973**	12,773
Accumulated depreciation	**(6,395)**	(5,949)
	6,578	6,824
Goodwill *(Note 17)*	**463**	464
Intangible assets (Note 18)	**364**	355
Deferred income tax assets *(Note 10)*	**24**	53
Risk management assets *(Notes 13 and 14)*	**684**	785
Other assets *(Note 19)*	**237**	242
Total assets	**10,304**	10,996
Accounts payable and accrued liabilities	**595**	413
Current portion of decommissioning and other provisions *(Note 20)*	**67**	39
Risk management liabilities *(Notes 13 and 14)*	**101**	66
Income taxes payable	**64**	6
Dividends payable *(Note 23)*	**34**	54
Current portion of long-term debt and finance lease obligations *(Note 21)*	**747**	639
	1,608	1,217
Credit facilities, long-term debt, and finance lease obligations *(Note 21)*	**2,960**	3,722
Decommissioning and other provisions *(Note 20)*	**403**	304
Deferred income tax liabilities *(Note 10)*	**549**	712
Risk management liabilities *(Notes 13 and 14)*	**40**	48
Defined benefit obligation and other long-term liabilities *(Note 22)*	**359**	330
Equity		
Common shares *(Note 23)*	**3,094**	3,094
Preferred shares *(Note 24)*	**942**	942
Contributed surplus	**10**	9
Deficit	**(1,209)**	(933)
Accumulated other comprehensive income *(Note 25)*	**489**	399
Equity attributable to shareholders	**3,326**	3,511
Non-controlling interests *(Note 11)*	**1,059**	1,152
Total equity	**4,385**	4,663
Total liabilities and equity	**10,304**	10,996

Commitments and contingencies *(Note 32)*

Subsequent events *(Note 34)*

See accompanying notes.

Gordon D. Giffin Alan J. Fohrer

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, 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
Net earnings (loss)	**–**	**–**	**–**	(160)	**–**	**(160)**	42	**(118)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**–**	**–**	**–**	**–**	**(25)**	**(25)**	**–**	**(25)**
Net gains on derivatives designated as cash flow hedges, net of tax	**–**	**–**	**–**	**–**	**106**	**106**	**–**	**106**
Net actuarial gains on defined benefits plans, net of tax	**–**	**–**	**–**	**–**	(6)	**(6)**	**–**	**(6)**
Intercompany available-for-sale investments	**–**	**–**	**–**	**–**	**11**	**11**	**(11)**	**–**
Total comprehensive income				**(160)**	**86**	**(74)**	**31**	**(43)**
Common share dividends	**–**	**–**	**–**	**(34)**	**–**	**(34)**	**–**	**(34)**
Preferred share dividends	**–**	**–**	**–**	**(30)**	**–**	**(30)**	**–**	**(30)**
Changes in non-controlling interests in TransAlta Renewables *(Note 4)*	**–**	**–**	**–**	**(52)**	**4**	**(48)**	**48**	**–**
Effect of share-based payment plans	**–**	**–**	**1**	**–**	**–**	**1**	**–**	**1**
Distributions paid, and payable, to non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**(172)**	**(172)**
Balance, Dec 31, 2017	**3,094**	**942**	**10**	**(1,209)**	**489**	**3,326**	**1,059**	**4,385**

(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)*	**2017**	2016	2015
Operating activities			
Net earnings (loss)	**(118)**	276	116
Depreciation and amortization *(Note 33)*	**708**	664	605
Gain on sale of assets *(Note 4)*	**(1)**	(1)	(262)
Accretion of provisions *(Note 20)*	**23**	20	21
Decommissioning and restoration costs settled *(Note 20)*	**(19)**	(23)	(24)
Deferred income tax expense (recovery) *(Note 10)*	**(15)**	15	86
Unrealized (gain) loss from risk management activities	**(48)**	58	61
Unrealized foreign exchange (gain) loss	**22**	(1)	13
Provisions	**(7)**	(123)	101
Asset impairment charges (reversals) *(Note 6)*	**20**	28	(2)
Other non-cash items	**175**	(242)	(41)
Cash flow from operations before changes in working capital	**740**	671	674
Change in non-cash operating working capital balances *(Note 29)*	**(114)**	73	(242)
Cash flow from operating activities	**626**	744	432
Investing activities			
Additions to property, plant, and equipment *(Notes 16 and 33)*	**(338)**	(358)	(476)
Additions to intangibles *(Notes 18 and 33)*	**(51)**	(21)	(26)
Restricted cash *(Notes 19 and 21)*	**(30)**	—	—
Loan receivable *(Note 19)*	**(38)**	—	—
Acquisition of renewable energy facilities, net of cash acquired *(Note 4)*	**—**	—	(101)
Proceeds on sale of property, plant, and equipment	**3**	6	7
Proceeds on sale of Wintering Hills facility and Solomon disposition *(Note 4)*	**478**	—	—
Income tax expense on Solomon disposition *(Notes 4 and 10)*	**(56)**	—	—
Realized gains (losses) on financial instruments	**6**	(6)	(12)
Decrease in finance lease receivable	**59**	56	23
Other	**(3)**	2	24
Change in non-cash investing working capital balances	**57**	(6)	(12)
Cash flow from (used in) investing activities	**87**	(327)	(573)
Financing activities			
Net increase (decrease) in borrowings under credit facilities *(Note 21)*	**26**	(315)	218
Repayment of long-term debt *(Note 21)*	**(814)**	(88)	(758)
Issuance of long-term debt *(Note 21)*	**260**	361	487
Dividends paid on common shares *(Note 23)*	**(46)**	(69)	(124)
Dividends paid on preferred shares *(Note 24)*	**(40)**	(42)	(46)
Net proceeds on sale of non-controlling interest in subsidiary *(Note 4)*	**—**	162	404
Realized gains (losses) on financial instruments	**106**	(2)	87
Distributions paid to subsidiaries' non-controlling interests *(Note 11)*	**(172)**	(151)	(99)
Decrease in finance lease obligations *(Note 21)*	**(17)**	(16)	(13)
Other	**(6)**	(3)	(7)
Cash flow from (used in) financing activities	**(703)**	(163)	149
Cash flow from operating, investing, and financing activities	**10**	254	8
Effect of translation on foreign currency cash	**(1)**	(3)	3
Increase in cash and cash equivalents	**9**	251	11
Cash and cash equivalents, beginning of year	**305**	54	43
Cash and cash equivalents, end of year	**314**	305	54
Cash income taxes paid	**14**	27	17
Cash interest paid	**230**	235	242

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, US 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 ("US"), 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 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 TransAlta's Board of Directors (the "Board") on March 1, 2018.

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, the 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 its 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	2-14 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	2-14 years
Capital spares and other	2-30 years

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

H. Intangible Assets

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

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

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

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

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

Software	2-7 years
Power sale contracts	5-20 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 occur 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, if there has been an increase in the recoverable amount, the impairment loss previously recognized is reversed. 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 installments 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 2015 to 2017 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. Project Development Costs

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

VI. Provisions for Decommissioning and Restoration Activities

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

VII. Useful Life of PP&E

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

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

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

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

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

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

3. Accounting Changes

A. Current Accounting Changes

Change in Estimates - Useful Lives
As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(H), 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 some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $58 million. The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 4(B) for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2017. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the life of Sundance Unit 2 to 2021 (see Note 4(B) for further details). As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017 decreased in total by approximately $4 million.

B. Future Accounting Changes

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

I. IFRS 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 completed the review and accounting assessment of its revenue streams and underlying contracts with customers and the quantification of impacts. The majority of the Corporation's revenues within the scope of IFRS 15 are earned through the sale of capacity and energy under both long-term arrangements and merchant mechanisms, and from the sale of renewable energy certificates. IFRS 15 requires the application of a five-step model to determine when to recognize revenue, and at what amount. 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. Depending on whether certain criteria are met, revenue is recognized either over time, in a manner that depicts the entity's performance, or at a point in time, when control is transferred to the customer. The Corporation has not identified any significant differences in the timing or amount of recognition of revenue as a result of IFRS 15, with the exception of one difference, as discussed below.

IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer ("significant financing component"). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. The Corporation was required to apply this to one of the Corporation's contracts with a customer. The application of the significant financing component requirements results in the recognition of interest expense over the financing period and a higher amount of revenue.

The Corporation has chosen to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the consolidated financial statements as at and for the year ended Dec. 31, 2018, will not be restated. Instead, the Corporation will recognize the cumulative impact of the initial application of the standard in retained earnings as at Jan. 1, 2018. The cumulative impact of applying the significant financing component requirements to the identified contract results in a $12 million (net of tax impacts) charge to retained earnings.

II. IFRS 9 *Financial Instruments*

In July 2014, the IASB issued the final version of IFRS 9, which replaces IAS 39 *Financial Instruments: Recognition and* Measurement. IFRS 9 includes guidance on the classification and measurement of financial assets and financial liabilities, impairment of financial assets, and a new hedge accounting model. IFRS 9 is required to be adopted retrospectively for annual periods beginning on or after Jan. 1, 2018 with early adoption permitted. IFRS 9 will be adopted by the Corporation on Jan. 1, 2018.

Under the new 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. The classification and measurement depends on the contractual cash flow characteristics of the financial asset and the entity's business model for managing the financial asset. The classification requirements for financial liabilities are largely unchanged from IAS 39. Based on the assessment performed to date, the Corporation's classification and measurement of financial assets is not expected to be materially affected by the initial application of IFRS 9.

The new general hedge accounting model is intended to be simpler and more closely focused 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. Based on its assessment to date, the Corporation is not expected to be materially affected by the new general hedge accounting model. However, where the Corporation uses foreign exchange forward contracts to hedge anticipated payments in foreign currency, and the hedged transaction results in a non-financial item, the reclassification of gains or losses on the hedges will be presented directly in the Statement of Changes in Equity as a reclassification from accumulated other comprehensive income.

The Corporation has completed its implementation plan, which included reviewing its various types of financial instruments to determine the impact of the new classification guidance, and assessing the historical credit loss data as well as considering reasonable and supportable forward-looking information that was available without undue cost or effort. There are no significant changes to classification and measurement identified. The Corporation is not expected to be materially impacted by the initial implementation of the expected credit loss impairment model. Ongoing disclosures are expected to be more extensive and will include information about the Corporation's risk management strategy, how the risk management activities may affect the amount, timing and uncertainty of future cash flows and the effect that hedge accounting has had on the statement of financial position, the statement of comprehensive income and the statement of changes in equity.

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.

We are in the process of completing an initial scoping assessment for IFRS 16 and have prepared a detailed project plan. We anticipate that most of the effort under the implementation plan will occur in mid-to-late 2018. It is not yet possible to make reliable estimates of the potential impact of IFRS 16 on our 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. Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C Power Purchase Arrangements ("Sundance PPAs") effective March 31, 2018.

The termination of the Sundance PPAs by the Balancing Pool was expected and the Corporation is working to ensure it receives the termination payment that it believes it is entitled to under the Sundance PPAs and applicable legislation. The expected impacts of the termination include approximately $215 million in compensation for the net book value of the assets as compared to the Balancing Pool's estimate of approximately $157 million. The Balancing Pool's estimate differs because it excludes certain mining assets that the Corporation believes should be included in the net book value calculation.

B. Transition to Clean Power in Alberta and Sundance Unit 1 Impairment Charge

I. Sundance and Keephills Units 1 and 2 Coal-to-Gas Conversion Strategy

On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. The strategy includes mothballing and retiring the following Sundance Units:

- retiring of Sundance Unit 1 effective Jan. 1, 2018;
- temporarily mothballing Sundance Unit 2 effective Jan. 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 3 effective April 1, 2018, for a period of up to two years;
- temporarily mothballing Sundance Unit 4 effective April 1, 2019, for a period of up to two years; and
- temporarily mothballing Sundance Unit 5 effective April 1, 2018, for a period of up to one year.

As a result of the clarity provided by the draft coal-to-gas conversion rules proposed by the Government of Canada, the Corporation has determined to accelerate the conversion of Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, a year earlier than originally planned. Although not yet finalized, the Government of Canada has proposed coal-to-gas conversion rules that would extend the life of the Corporation's gas conversion units by five to ten years past their federal end of coal life, depending on their CO_2 emissions profile. The proposed rules would see the life of TransAlta's entire coal-fired fleet extended by an aggregate of approximately 75 years. In addition to extending their operating lives, the benefits of converting units to gas generation include significantly lowering carbon intensities, emissions, and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility.

Temporarily mothballing the combination of Sundance Units throughout 2018 and 2019 ensures that two Sundance Units can operate at high-capacity utilizations with lower costs throughout the period to 2020 when additional power will be needed in the Alberta market. The mothballing of the units will also assist the Corporation in its preparations for converting Sundance Units 3 to 6 and Keephills Units 1 and 2 from coal-fired generation to gas-fired generation in the 2021 to 2022 timeframe, thereby extending the useful lives of these assets until the mid-2030s.

II. Gas Supply for Coal-to-Gas Conversions

On Dec. 6, 2017, the Corporation entered into a letter of intent with Tidewater Midstream and Infrastructure Ltd. ("Tidewater") to construct a 120-kilometre natural gas pipeline from Tidewater's Brazeau River complex to the Corporation's generating units at Sundance and Keephills facilities. The pipeline is expected to provide initial capacity of 130 million cubic feet of gas per day by 2020, and to have expansion capability to 340 million cubic feet of gas per day. The initial capacity will support fuel blending, using a fuel combination of coal and gas for generation, which will reduce the marginal cost as well as emissions. The Corporation will have the option to acquire up to a 50 per cent interest in the pipeline, which, if exercised, would reduce the costs associated with the tolling agreement.

The decision to work with Tidewater advances the timeframe for the construction of a pipeline and permits the acceleration of plant conversions. TransAlta remains of the view that having at least two pipelines supplying natural gas would reduce operational risks and continues to advance discussions with other parties to construct additional pipelines to meet the remaining gas supply requirements for the facilities.

III. Sundance Units 1 and 2
Federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 will be shut down two years early, the federal Minister of Environment has agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This will provide the Corporation with flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market.

Sundance Units 1 and 2 collectively make up 560 MW of the 2,141 MW capacity of the Sundance power plant, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expired on Dec. 31, 2017.

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of $20 million due to the Corporation's decision to early retire Sundance Unit 1. See Note 6 for further details.

C. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited
On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidairy of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the power station has not reached commercial operation within a specified time period. FMG continues to be of the view that South Hedland Power Station has yet to achieve commercial operation.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies.

Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation will take all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA.

The South Hedland Power Station has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

D. Re-acquisition of Solomon Power Station
On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action to recover all, or a significant portion of, this amount from FMG.

E. Kent Hills 3 Wind Project
During the second quarter of 2017, a subsidiary of TransAlta Renewables Inc. ("TransAlta Renewables"), Kent Hills Wind LP ("KHWLP"), entered into a long-term contract with New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 wind project. At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035, matching the life of Kent Hills 2 and Kent Hills 3 wind projects.

This is an expansion of the Corporation's existing Kent Hills wind farm, increasing the total operating capacity of the Kent Hills wind farm to approximately 167 MW. As part of the regulatory process, the Corporation submitted an Environmental Impact Assessment to the Province of New Brunswick in the third quarter of 2017. The Corporation expects to begin the construction phase in the spring of 2018.

F. TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, KHWLP, closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds will be used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project (upon meeting certain completion tests and other specified conditions). The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers, Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP. Proceeds of $30 million were classified as restricted cash as at Dec. 31, 2017, and will be released from the construction reserve account upon commissioning.

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million, which included the principal of $191 million, an early redemption premium of $6 million, and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

G. Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of Series E Preferred Shares into Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and the dividend rate remains fixed for the subsequent five-year period. See Note 24 for further details.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and the dividend remains fixed for the subsequent five-year period. See Note 13 for further details.

H. 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 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 also entered into a Memorandum of Understanding ("MOU") 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.

I. 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 in 2016. 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.

J. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP, 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 of 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.

K. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was 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(B).

L. 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 recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for proceeds of $61 million.

M. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables' indirect wholly owned subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

N. 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 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. On Nov. 9, 2017, TransAlta Renewables repaid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. The convertible debenture was scheduled to mature on Dec. 31, 2020.

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 in 2016.

O. 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 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 was classified as assets held for sale (see Note 4(L)). The Corporation sold its interest in the Wintering Hills facility on March 1, 2017.

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 per cent, 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 from 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.

P. US Solar and Wind Acquisition

On Oct. 1, 2015, the Corporation acquired 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 acquired 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 from 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.

Q. Sale of Economic Interest in Australian Assets to TransAlta Renewables

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 consisted of 575 MW of power generation from six operating assets and the South Hedland power project then under construction, as well as the 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 provided voting rights equivalent to the common shares, were non-dividend paying and converted into common shares on the commissioning of the South Hedland Power Station.

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to by TransAlta Renewables.

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 received shareholder approval 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.

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

On Nov. 26, 2015, the Corporation completed the sale to Alberta Investment Management Corporation of 20,512,820 common shares of TransAlta Renewables for gross proceeds of $200 million (net proceeds of $193 million).

S. 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.

T. Changes in Internal Capitalization of US 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.

5. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2017**		2016		2015	
	Fuel and purchased power	**Operations, maintenance, and administration**	Fuel and purchased power	Operations, maintenance, and administration	Fuel and purchased power	Operations, maintenance, and administration
Fuel	**775**	**—**	755	—	775	—
Coal inventory writedown (recovery)	**—**	**—**	(4)	—	22	—
Purchased power	**162**	**—**	143	—	147	—
Mine depreciation	**73**	**—**	63	—	59	—
Salaries and benefits	**6**	**248**	6	249	5	250
Other operating expenses	**—**	**269**	—	240	—	242
Total	**1,016**	**517**	963	489	1,008	492

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. Alberta Merchant CGU

During 2017, 2016, and 2015, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan ("CLP"), the future design parameters of the Alberta electricity market, and federal policies on the carbon levy and greenhouse gas ("GHG") emissions. Economic conditions also contributed to continued oversupply conditions and depressed market prices throughout 2015 to 2017. The Corporation assessed whether these factors, and events arising during the latter part of 2016, which are more fully discussed below, presented an indicator of impairment for its Alberta Merchant CGU. In consideration of the composition of this CGU, the Corporation 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 for any of these years, but for all years, a sensitivity analysis associated with these factors was performed to confirm the continued existence of adequate excess of estimated recoverable amount over book value. This analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU in each of 2017, 2016, and 2015, due to the Corporation's large merchant renewable fleet in the province.

I. 2017

Sundance Unit 1

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintains the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU to 2021.

II. 2016

On Nov. 24, 2016, the Corporation reached an Off-Coal Agreement with the Government to receive annual cash payments of approximately $37.4 million, net to the Corporation (see Note 4(H) for further details) in return for ceasing coal-fired generation by the end of 2030, among other conditions. Furthermore, the Corporation 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 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 Government and the Corporation and does not impose any obligations on, or constrain the discretion and authority of, the Government. The announcement of the intention to move to a capacity market is expected to impact the Alberta market mechanisms. 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 Government or the Alberta Electric System Operator, which is overseeing the development of the capacity market, to determine if a change is required. The Corporation has not modified its previous conclusions on the determination of the Alberta Merchant CGU.

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 Dec. 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 in 2016.

III. 2015

In 2015, the Government announced its 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 refined its approach to GHG by announcing the adoption of 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.

B. US Coal

The Corporation considered possible indicators of impairment at US Coal in 2017, 2016, and 2015, as discussed in more detail below.

Fair value less costs of disposal of the CGU was estimated to approximate its carrying amount, and accordingly, no impairment charge was recorded in 2017, 2016 or 2015. 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 by optimizing of its operating activities and capital plan.

The valuations are subject to measurement uncertainty based on the key assumptions outlined below, 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 plant, after its projected cessation of operation in its current form in 2025.

I. 2017

During 2017, the Corporation renegotiated rail transportation and coal supply agreements. Accordingly, the Corporation completed an estimate of the impact for the coal cost changes combined with updated power prices to determine whether the US Coal CGU had an indicator of impairment. The Corporation concluded that there is no indicator of impairment. The Corporation utilized the Corporation's long-range forecast and the following key assumptions:

Mid-Columbia annual average power prices	US$21.50 to US$34.81 per MWh
On-highway diesel fuel on coal shipments	US$2.08 to US$2.29 per gallon
Discount rates	7.9 to 9.0 per cent

II. 2016

During 2016, the Corporation considered possible impairment at the US Coal CGU and found that the fair value less costs to sell approximated the then 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

III. 2015

During 2015, the Corporation considered possible impairment at the US Coal CGU and found that the fair value less costs to sell approximated the then 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

Impairment reversals of $2 million resulted from additional recoveries from the disposal of the Centralia gas plant in 2014.

7. Finance Lease Receivables

A. Re-acquisition of Solomon Power Station

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe, a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017 and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not be held back and the Corporation is taking action to recover all, or a significant portion of, this amount from FMG.

B. Amounts Receivable

Amounts receivable under the Corporation's finance leases, associated with the Fort Saskatchewan cogeneration facility and the Poplar Creek cogeneration facility, and in 2016 the Solomon Power Station, are as follows:

As at Dec. 31	**2017**		2016	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**68**	**66**	124	119
Second to fifth years inclusive	**110**	**82**	376	291
More than five years	**140**	**126**	637	311
	318	**274**	1,137	721
Less: unearned finance lease income	**44**	**—**	592	—
Add: unguaranteed residual value	**—**	**—**	233	57
Total finance lease receivables	**274**	**274**	778	778

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables *(Note 12)*	**59**	59
Long-term portion of finance lease receivables	**215**	719
	274	778

8. Net Other Operating (Income) Losses

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

Year ended Dec. 31	2017	2016	2015
Alberta Off-Coal Agreement	(40)	–	–
Mississauga cogeneration facility NUG Contract	(9)	(191)	–
Market Surveillance Administrator Agreement settlement	–	–	56
Insurance recoveries	–	(3)	(31)
Net other operating (income) losses	**(49)**	(194)	25

A. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into the OCA with 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 OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2020.

B. Mississauga Cogeneration Facility Contract

2016

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the 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.

2017

During the fourth quarter of 2017, the Corporation renegotiated the facility's land lease agreement at a lower cost than previously estimated in 2016, and accordingly, recognized a gain of $9 million.

C. 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 paid 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 2016. As a result of the approval, the Corporation discontinued the appeal of the AUC's decision.

D. Insurance Recoveries

There were no insurance recoveries in 2017.

During 2016, the Corporation received $3 million in insurance recoveries (2015 - $31 million), of which $2 million (2015 - $6 million) related to business interruption insurance claims and $1 million related to claims for replacement and refurbishment of equipment for certain wind facilities (2015 - $7 million for Canadian Coal facilities).

In 2015 the Corporation received $18 million of insurance recoveries related to claims for the replacement and refurbishment of certain hydro facilities as a result of the flooding in Southern Alberta in 2013. Additionally, in 2015, $12 million of insurance proceeds were received related to claims for repair costs on certain hydro facilities as a result of flooding in Southern Alberta in 2013 and were accounted for as a reduction to period operations, maintenance, and administration costs.

9. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2017**	2016	2015
Interest on debt	**218**	218	218
Interest income	**(7)**	(2)	(2)
Capitalized interest *(Note 16)*	**(9)**	(16)	(9)
Loss on redemption of bonds *(Note 4(F))*	**6**	1	—
Interest on finance lease obligations	**3**	3	4
Credit facility fees, bank charges, and other interest	**18**	19	10
Keephills 1 outage interest accruals (reversals) *(Note 4)*	**—**	(10)	9
Other	**(3)**	(4)	—
Accretion of provisions *(Note 20)*	**21**	20	21
Net interest expense	**247**	229	251

10. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2017	2016	2015
Earnings before income taxes	**(54)**	314	221
Net earnings attributable to non-controlling interests not subject to tax	**(35)**	(109)	(34)
Adjusted earnings before income taxes	**(89)**	205	187
Statutory Canadian federal and provincial income tax rate (%)	**26.8**	26.7	25.9
Expected income tax expense (recovery)	**(24)**	55	48
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(11)**	(16)	(16)
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	**(15)**	(10)	(56)
Statutory and other rate differences	**110**	1	20
Other	**4**	(3)	—
Income tax expense	**64**	38	105
Effective tax rate (%)	**72**	19	56

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2017	2016	2015
Current income tax expense[1]	**79**	23	24
Adjustments in respect of current income tax of previous years	**—**	—	(5)
Adjustments in respect of deferred income tax of previous years	**—**	(3)	5
Deferred income tax expense related to the origination and reversal of temporary differences	**(110)**	16	22
Deferred income tax expense related to temporary difference on investment in subsidiary[2]	**—**	11	95
Deferred income tax expense resulting from changes in tax rates or laws[3]	**110**	1	20
Deferred income tax recovery arising from the reversal of writedown of deferred income tax assets[4]	**(15)**	(10)	(56)
Income tax expense	**64**	38	105

Year ended Dec. 31	2017	2016	2015
Current income tax expense	**79**	23	19
Deferred income tax expense (recovery)	**(15)**	15	86
Income tax expense	**64**	38	105

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon Power Station on Nov. 1, 2017.
(2) 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.
(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act, *which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income. 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.*
(4) During the year ended Dec. 31, 2017, the Corporation reversed a previous writedown of deferred income tax assets of $15 million (2016 - $10 million writedown reversal, 2015 - $56 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US 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 US operations to utilize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2037. Recognized OCI during the years ended Dec. 31, 2017 and 2016, has 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	2017	2016	2015
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(108)**	51	89
Net impact related to net investment hedges	**(7)**	16	8
Net actuarial gains (losses)	**(4)**	4	—
Share issuance costs	**—**	—	(4)
Loss on sale of investment in subsidiary	**—**	—	(8)
Income tax expense reported in equity	**(119)**	71	85

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2017	2016
Net operating loss carryforwards	**541**	768
Future decommissioning and restoration costs	**117**	103
Property, plant, and equipment	**(1,009)**	(1,114)
Risk management assets and liabilities, net	**(160)**	(282)
Employee future benefits and compensation plans	**74**	70
Interest deductible in future periods	**50**	90
Foreign exchange differences on US-denominated debt	**42**	69
Deferred coal revenues	**16**	17
Other deductible temporary differences	**22**	3
Net deferred income tax liability, before writedown of deferred income tax assets	**(307)**	(276)
Writedown of deferred income tax assets	**(218)**	(383)
Net deferred income tax liability, after writedown of deferred income tax assets	**(525)**	(659)

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

As at Dec. 31	2017	2016
Deferred income tax assets[1]	**24**	53
Deferred income tax liabilities	**(549)**	(712)
Net deferred income tax liability	**(525)**	(659)

(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, 2017, the Corporation had recognized a net liability of $4 million (2016 - $7 million) related to uncertain tax positions. The decrease was the result of settlements with taxation authorities.

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, 2017
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	36% - Public shareholders
Kent Hills Wind LP(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.

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables.

As a result of the conversion of Class B shares and 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
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 to July 31, 2017	64.0	59.8
Aug. 1, 2017 and thereafter	64.0	64.0

Year ended Dec. 31	2017	2016	2015
Revenues	**459**	259	236
Net earnings	**13**	1	198
Total comprehensive income	**(24)**	40	204
Amounts attributable to the non-controlling interests:			
Net earnings	**11**	2	63
Total comprehensive income	**—**	18	65
Distributions paid to non-controlling interests	**85**	83	43

As at Dec. 31	2017	2016
Current assets	**145**	109
Long-term assets	**3,483**	3,732
Current liabilities	**(356)**	(537)
Long-term liabilities	**(1,075)**	(1,237)
Total equity	**(2,197)**	(2,067)
Equity attributable to non-controlling interests	**(812)**	(851)
Non-controlling interests' share (per cent)	**36.0**	40.2

B. TA Cogen

Year ended Dec. 31	2017	2016	2015
Results of operations			
Revenues	**175**	274	288
Net earnings	**61**	211	61
Total comprehensive income	**61**	258	77
Amounts attributable to the non-controlling interest:			
Net earnings	**31**	105	31
Total comprehensive income	**31**	128	38
Distributions paid to Canadian Power Holdings Inc.	**87**	68	56

As at Dec. 31	2017	2016
Current assets	**193**	171
Long-term assets	**404**	538
Current liabilities	**(73)**	(65)
Long-term liabilities	**(26)**	(35)
Total equity	**(498)**	(609)
Equity attributable to Canadian Power Holdings Inc.	**(247)**	(301)
Non-controlling interest share (per cent)	**49.99**	49.99

12. Trade and Other Receivables

As at Dec. 31	2017	2016
Trade accounts receivable	**693**	446
Mississauga recontracting receivable	**108**	112
Net trade receivables	**801**	558
Collateral paid *(Note 14)*	**67**	77
Current portion of finance lease receivables *(Note 7)*	**59**	59
Current portion of loan receivable *(Note 19)*	**5**	–
Income taxes receivables	**1**	9
Trade and other receivables	**933**	703

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, 2017

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents[1]	–	–	314	–	314
Restricted cash	–	–	30	–	30
Trade and other receivables	–	–	933	–	933
Long-term portion of finance lease receivables	–	–	215	–	215
Risk management assets					
Current	82	137	–	–	219
Long-term	638	46	–	–	684
Other assets	–	–	33	–	33
Financial liabilities					
Accounts payable and accrued liabilities	–	–	–	595	595
Dividends payable	–	–	–	34	34
Risk management liabilities					
Current	8	93	–	–	101
Long-term	2	38	–	–	40
Credit facilities, long-term debt and finance lease obligations[2]	–	–	–	3,707	3,707

(1) Includes cash equivalents of nil.
(2) Includes current portion.

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.

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 certain unobservable 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	2017		2016	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**853**	**+130 -130**	907	+76 -69
Long-term power sale - Alberta	**(1)**	**+2 -2**	(3)	+5 -5
Unit contingent power purchases	**44**	**+7 -9**	13	+2 -4
Structured products - Eastern US	**17**	**+8 -7**	24	+8 -8
Others	**5**	**+9 -9**	6	+3 -3

i. Long-Term Power Sale - US

The Corporation has a long-term fixed price power sale contract in the US 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 2019, 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, 2017 are US$25 - US$34 (Dec. 31, 2016 - US$27 - US$36). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2016 - 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, 2016 to Dec. 31, 2017, the base fair value and the sensitivity values have decreased by approximately $50 million and $8 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 2022, 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, 2017, are $63 - $67 (Dec. 31, 2016 - $68 - $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, 2017, are nil (Dec. 31, 2016 - nil) and 2.20 per cent to 2.76 per cent (Dec. 31, 2016 – 2.15 per cent to 3.62 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 1.1 per cent to 1.94 per cent (Dec. 31, 2016 - 0.75 per cent) and a change in volumetric discount rates of approximately 7.77 per cent to 10.46 per cent (Dec. 31, 2016 - 15.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern US

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, 2017, are 75 per cent to 159 per cent and 71 per cent to 88 per cent (Dec. 31, 2016 – 66 per cent to 128 per cent and 65 per cent to 88 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 7 per cent (Dec. 31, 2016 - 5 per cent) and a change in non-standard shape factors of approximately 6 per cent (Dec. 31, 2016 - 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, 2017, are 18 per cent to 54 per cent and 70 per cent (Dec. 31, 2016 – 20 per cent to 54 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 27 per cent to 32 per cent and 10 per cent, respectively (2016 - 10 per cent).

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.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2017, are as follows: Level I - $1 million net liability (Dec. 31, 2016 - nil), Level II - $42 million net liability (Dec. 31, 2016 - $14 million net liability), Level III - $771 million net asset (Dec. 31, 2016 - $758 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2017 are primarily attributable to the 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.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2017 and 2016, respectively:

	Year ended Dec. 31, 2017			Year ended Dec. 31, 2016		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**726**	**32**	**758**	640	(98)	542
Changes attributable to:						
Market price changes on existing contracts	**100**	**(2)**	**98**	163	13	176
Market price changes on new contracts	**—**	**33**	**33**	—	29	29
Contracts settled	**(57)**	**(10)**	**(67)**	(50)	88	38
Change in foreign exchange rates	**(50)**	**(2)**	**(52)**	(27)	—	(27)
Transfers into Level III	**—**	**1**	**1**	—	—	—
Net risk management assets at end of period	**719**	**52**	**771**	726	32	758
Additional Level III information:						
Gains recognized in other comprehensive income	**50**	**—**	**50**	136	—	136
Total gains included in earnings before income taxes	**57**	**29**	**86**	50	42	92
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**19**	**19**	—	130	130

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations, and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net asset fair value of $34 million as at Dec. 31, 2017 (Dec. 31, 2016 - $176 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2017, are primarily attributable to the settlement of contracts.

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**
	Level I	**Level II**	**Level III**	**Total**	**value**
Long-term debt[(1)] - Dec. 31, 2017	**—**	**3,708**	**—**	**3,708**	**3,638**
Long-term debt[(1)] - Dec. 31, 2016	—	4,271	—	4,271	4,221

(1) Includes current portion. 2016 excludes $67 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. The fair values of the loan receivable (see Note 19) and the finance lease receivables (see Note 7) approximate the carrying amounts.

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	**2017**	2016	2015
Unamortized net gain at beginning of year	**148**	202	188
New inception gains	**12**	10	28
Change in foreign exchange rates	**(7)**	(4)	28
Amortization recorded in net earnings during the year	**(48)**	(60)	(42)
Unamortized net gain at end of year	**105**	148	202

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, 2017

	Cash flow hedges	Fair value hedges	Not designated as a hedge	Total
Commodity risk management				
Current	**74**	**—**	**7**	**81**
Long-term	**636**	**—**	**11**	**647**
Net commodity risk management assets	**710**	**—**	**18**	**728**
Other				
Current	**—**	**—**	**37**	**37**
Long-term	**—**	**—**	**(3)**	**(3)**
Net other risk management assets (liabilities)	**—**	**—**	**34**	**34**
Total net risk management assets (liabilities)	**710**	**—**	**52**	**762**

As at Dec. 31, 2016

	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	769	—	(25)	744
Other				
Current	105	—	8	113
Long-term	59	3	1	63
Net other risk management assets (liabilities)	164	3	9	176
Total net risk management assets (liabilities)	933	3	(16)	920

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	2017				2016			
	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	**281**	**637**	**(159)**	**(38)**	315	744	(113)	(53)
Gross amounts set-off	**(43)**	**—**	**43**	**—**	(24)	(3)	24	3
Net amounts as presented in the Consolidated Statements of Financial Position	**238**	**637**	**(116)**	**(38)**	291	741	(89)	(50)

II. Hedges

a. Net Investment Hedges

The Corporation's hedges of its net investment in foreign operations in 2017 were comprised of US-dollar-denominated long-term debt with a face value of US$480 million (2016 - US$630 million). 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	2017		2016	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**1,997**	**44**	4,916	—

During 2017, additional unrealized pre-tax gains of $2 million (2016 - nil, 2015 - $3 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, 2017, cumulative gains of $1 million (2016 - $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.

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. As at March 31, 2017, cumulative gains on the cash flow hedges of approximately $3 million will continue to be deferred in Accumulated Other Comprehensive Income and will be reclassified to net earnings as the forecasted transactions (interest payments) occur. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

As at Dec. 31		**2017**				2016	
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							
CAD9	**USD7**	**—**	**2018**	—	—	—	—
CAD14	**EUR9**	**—**	**2018**	—	—	—	—
AUD1	**JPY119**	**—**	**2018**	AUD8	JPY710	1	2017
Foreign Exchange Forward Contracts - foreign-denominated debt							
—	**—**	**—**	**—**	CAD26	USD20	—	2018
Cross-Currency Swaps - foreign-denominated debt							
—	—	—	—	CAD434	USD400	104	2017
—	**—**	**—**	**—**	CAD306	USD270	59	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, 2017			
		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	**163**	Revenue	**(172)**	Revenue	**—**
		Fuel and purchased power	**—**	Fuel and purchased power	**—**
Foreign exchange forwards on commodity contracts	**—**	Revenue	**—**	Revenue	**—**
Foreign exchange forwards on project hedges	**(1)**	Property, plant, and equipment	**—**	Foreign exchange (gain) loss	**—**
Foreign exchange forwards on US debt	**—**	Foreign exchange (gain) loss	**3**	Foreign exchange (gain) loss	**—**
Cross-currency swaps	**(26)**	Foreign exchange (gain) loss	**24**	Foreign exchange (gain) loss	**—**
Forward starting interest rate swaps	**—**	Interest expense	**7**	Interest expense	**—**
OCI impact	**136**	**OCI impact**	**(138)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $85 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.

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 US 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(B) for further details.

Year ended Dec. 31, 2015					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts		Revenue	(110)	Revenue	5
	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

During 2015, total unrealized pre-tax gains of $6 million were released from AOCI and recognized in earnings due to hedge de-designations for accounting purposes.

c. Fair Value Hedges

i. Interest Rate Risk Management

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain fair value hedges on US$50 million of debt. As at March 31, 2017, cumulative losses of approximately $2 million related to the fair value hedge, and recognized as part of the carrying value of the hedged debt, will be amortized to net earnings over the period to the debt's maturity. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively. See section II(b)(ii) of this note for information on these non-hedge derivatives.

During 2016, the Corporation had converted a portion of its fixed interest rate debt with a rate of 6.65 per cent to a floating interest rate based on the US LIBOR rate using interest rate swaps as outlined below:

As at Dec. 31	2017		2016		
Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
—	—	—	**USD50**	3	2018

Including interest rate swaps outlined in section II(b)(ii) of this note, and the above swap in 2016, 6 per cent of the Corporation's debt as at Dec. 31, 2017 is subject to floating interest rates (2016 - 6 per cent).

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	2017		2016	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**14,688**	**7,348**	19,362	19,060
Natural gas *(GJ)*	**74,195**	**103,805**	146,113	173,187
Transmission *(MWh)*	**1**	**3,455**	—	3,429
Emissions *(tonnes)*	**516**	**717**	1,370	1,370
Heating oil *(gallons)*	**—**	**—**	—	294

b. Other Non-Hedge Derivatives

i. Foreign Currency

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. Changes in these risk management assets and liabilities related to these discontinued hedge positions will be reflected within net earnings prospectively.

As at Dec. 31		**2017**				2016	
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
AUD170	**CAD157**	**(9)**	**2018-2021**	**USD152**	**CAD216**	12	2017-2020
USD73	**CAD104**	**11**	**2018-2021**	**AUD232**	**CAD219**	(3)	2017-2020
Foreign Exchange Forward Contracts - foreign-denominated debt							
CAD294	**USD230**	**(4)**	**2018**	—	—	—	—
Cross Currency Swaps - foreign-denominated debt							
CAD306	**USD270**	**35**	**2018**	—	—	—	—

ii. Interest Rate

The Corporation has converted a portion of its fixed interest rate debt with a rate of 6.65 per cent (2016 - 6.65 per cent) to a floating interest rate based on the US LIBOR rate using interest rate. The Corporation has converted a portion of its floating rate debt to a fixed rate of 4.7 per cent.

As at Dec. 31		**2017**			2016	
	Notional amount	**Fair value asset**	**Maturity**	Notional amount	Fair value asset	Maturity
Fixed rate debt	**USD50**	**1**	**2018**	—	—	—
Floating rate debt	**USD22**	**—**	**2018-24**	—	—	—

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, 2017, the Corporation recognized a net unrealized gain of $45 million (2016 - loss of $63 million, 2015 - loss of $51 million) related to commodity derivatives.

For the year ended Dec. 31, 2017, a gain of $28 million (2016 - gain of $9 million, 2015 - loss of $1 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized losses of $2 million (2016 - gains of $4 million, 2015 - loss of $11 million) and net realized gains of $30 million (2016 - gains of $5 million, 2015 - gains of $10 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, 2017, associated with the Corporation's proprietary trading activities was $5 million (2016 - $2 million, 2015 - $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, 2017, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $16 million (2016 - $19 million, 2015 - $24 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, 2017, associated with these transactions was $5 million (2016 - $7 million, 2015 - $1 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 (2016 - 15 basis point, 2015 - 15 basis point) increase or decrease is a reasonable potential change over the next quarter in market interest rates.

Year ended Dec. 31	**2017**		2016		2015	
	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 US dollar, the Japanese yen, the euro 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(Q), the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in the USD and AUD in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the 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 to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In 2016, a $5 million loss was recognized. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program. In 2017, a $6 million foreign exchange loss was recognized.

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 (2016 and 2015 - 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	2017		2016		2015	
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)**	**—**	(5)	—	2	5
AUD	**(7)**	**—**	(7)	—	(3)	—
Total	**(12)**	**—**	(12)	—	(1)	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, third-party credit insurance, 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. 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, 2017:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables(1)	87	13	**100**	**933**
Long-term finance lease receivables	96	4	**100**	**215**
Risk management assets(1)	99	1	**100**	**903**
Loan receivable(2)	—	100	**100**	**33**
Total				**2,084**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparty has no external credit rating. Excludes $5 million current portion classified in trade and other receivables.

The Corporation's maximum exposure to credit risk at Dec. 31, 2017, 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, 2017, was $40 million (2016 - $14 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing, and general corporate purposes. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. As at Dec. 31, 2017, 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:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Accounts payable and accrued liabilities	595	—	—	—	—	—	595
Long-term debt(1)	730	469	472	100	581	1,312	3,664
Commodity risk management assets	(81)	(94)	(88)	(102)	(103)	(260)	(728)
Other risk management (assets) liabilities	(37)	1	1	1	—	—	(34)
Finance lease obligations	18	15	12	6	4	14	69
Interest on long-term debt and finance lease obligations(2)	177	153	125	102	95	692	1,344
Dividends payable	34	—	—	—	—	—	34
Total	**1,436**	**544**	**522**	**107**	**577**	**1,758**	**4,944**

(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, 2017, the Corporation provided $67 million (2016 - $77 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 included in accounts receivable in the statement of financial position.

II. Financial Assets Held as Collateral

At Dec. 31, 2017, the Corporation held $21 million (2016 - $21 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 included in accounts payable in the Consolidated Statements 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, 2017, the Corporation had posted collateral of $131 million (Dec. 31, 2016 - $116 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 $96 million (Dec. 31, 2016 - $49 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	**2017**	2016
Parts and materials	**118**	110
Coal	**58**	65
Deferred stripping costs	**11**	12
Natural gas	**9**	17
Purchased emission credits	**23**	9
Total	**219**	213

The change in inventory is as follows:

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
Net addition	**11**
Change in foreign exchange rates	**(5)**
Balance, Dec 31, 2017	**219**

No inventory is pledged as security for liabilities.

16. Property, Plant, and Equipment

A reconciliation of the changes in the carrying amount of PP&E is as follows:

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec 31, 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 charge - Wintering Hills *(Note 4)*	—	—	—	(28)	—	—	—	(28)
Reclassification to held for sale *(Note 4)*	—	—	—	(67)	—	—	—	(67)
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)
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
Additions	**—**	**—**	**—**	**—**	**—**	**334**	**4**	**338**
Additions - finance lease	**—**	**—**	**—**	**—**	**14**	**—**	**—**	**14**
Disposals	**—**	**—**	**(16)**	**(1)**	**(1)**	**—**	**(1)**	**(19)**
Impairment charge - Sundance Unit 1 *(Note 6)*	**—**	**(20)**	**—**	**—**	**—**	**—**	**—**	**(20)**
Revisions and additions to decommissioning and restoration costs	**—**	**82**	**12**	**15**	**42**	**—**	**—**	**151**
Retirement of assets	**—**	**(84)**	**(3)**	**(4)**	**(22)**	**—**	**(6)**	**(119)**
Change in foreign exchange rates	**(1)**	**(87)**	**3**	**(23)**	**(7)**	**(2)**	**(2)**	**(119)**
Transfers[3]	**1**	**121**	**461**	**29**	**24**	**(644)**	**(18)**	**(26)**
As at Dec 31, 2017	**95**	**5,888**	**1,982**	**3,228**	**1,315**	**95**	**370**	**12,973**
Accumulated depreciation								
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)
Reclassification to held for sale *(Note 4)*	—	—	—	(6)	—	—	—	(6)
Change in foreign exchange rates	—	(28)	(10)	—	(1)	—	—	(39)
Transfers	—	(239)	51	(2)	—	—	(1)	(191)
As at Dec 31, 2016	—	3,212	1,027	922	659	—	129	5,949
Depreciation	—	351	67	123	76	—	18	635
Retirement of assets	—	(62)	(2)	(3)	(18)	—	(5)	(90)
Disposals	—	—	(11)	(1)	—	—	—	(12)
Change in foreign exchange rates	—	(67)	(1)	(4)	(4)	—	—	(76)
Transfers[2]	—	(3)	(8)	—	—	—	—	(11)
As at Dec 31, 2017	**—**	**3,431**	**1,072**	**1,037**	**713**	**—**	**142**	**6,395**
Carrying amount								
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
As at Dec 31, 2017	**95**	**2,457**	**910**	**2,191**	**602**	**95**	**228**	**6,578**

(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.
(3) During the second quarter of 2017, the Corporation reclassified approximately $13 million of capital spares and other assets to inventory.

The Corporation capitalized $9 million of interest to PP&E in 2017 (2016 - $16 million) at a weighted average rate of 5.87 per cent (2016 – 5.93 per cent).

Finance lease additions in 2017 and 2016 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2017 was $65 million (2016 - $76 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	**2017**	2016
Hydro	**259**	259
Wind and Solar	**174**	175
Energy Marketing	**30**	30
Total goodwill	**463**	464

For the purposes of the 2017 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar segment 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. In 2017, the Corporation relied on the recoverable amounts determined in 2016 for the Hydro and Energy Marketing segments in performing the 2017 annual goodwill impairment review. No impairment of goodwill arose for any segment.

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 2017 models ranged between $22 to $218 per MWh during the forecast period (2016 - $32 to $301 per MWh). Discount rates used for the goodwill impairment calculation in 2017 ranged from 5.5 per cent to 6.0 per cent (2016 – 5.5 per cent to 6.0 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, 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
Additions	**—**	**31**	**—**	**20**	**51**
Change in foreign exchange rates	**—**	**(3)**	**—**	**—**	**(3)**
Transfers	**—**	**18**	**—**	**(15)**	**3**
As at Dec. 31, 2017	**178**	**314**	**223**	**29**	**744**
Accumulated amortization					
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
Amortization	**8**	**24**	**9**	**—**	**41**
Change in foreign exchange rates	**—**	**1**	**—**	**—**	**1**
Transfers	**2**	**—**	**(2)**	**—**	**—**
As at Dec. 31, 2017	**125**	**188**	**67**	**—**	**380**
Carrying amount					
As at Dec. 31, 2015	69	114	171	15	369
As at Dec. 31, 2016	63	105	163	24	355
As at Dec. 31, 2017	**53**	**126**	**156**	**29**	**364**

19. Other Assets

The components of other assets are as follows:

As at Dec. 31	2017	2016
South Hedland prepaid transmission access and distribution	**75**	—
Deferred licence fees	**13**	15
Project development costs	**53**	46
Deferred service costs	**15**	16
Mississauga long-term receivable *(Note 4)*	**—**	116
Long-term prepaids and other assets	**44**	44
Loan receivable	**33**	—
Keephills Unit 3 transmission deposit	**4**	5
Total other assets	**237**	242

South Hedland prepaid costs relate to certain prepaid electricity transmission and distribution costs that are amortized on a straigh-line basis over the South Hedland PPA contract life.

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

Project development costs 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 four 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 Notes 4 and 12 for further details.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 32.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $38 million (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022. The Corporation may, at any time, demand repayment of any advances outstanding for the purpose of funding any capital required. The current portion of $5 million is included in accounts receivable and the long-term portion of the $33 million is included in other assets.

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 four 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, 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
Liabilities incurred	**3**	**19**	**22**
Liabilities settled	**(19)**	**(31)**	**(50)**
Liabilities disposed(1)	**(8)**	**—**	**(8)**
Accretion	**23**	**—**	**23**
Revisions in estimated cash flows(2)	**41**	**1**	**42**
Revisions in discount rates(2)	**110**	**—**	**110**
Reversals	**—**	**(4)**	**(4)**
Change in foreign exchange rates	**(6)**	**(2)**	**(8)**
Balance, Dec 31, 2017	**437**	**33**	**470**

(1) Relates to the disposition of the Solomon power station and the sale of the Wintering Hills wind facility.
(2) During 2017, mainly as a result of the OCA (see Note 4(H)), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to the use of 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec 31, 2016	293	50	343
Current portion	27	12	39
Non-current portion	266	38	304
Balance, Dec 31, 2017	**437**	**33**	**470**
Current portion	**40**	**27**	**67**
Non-current portion	**397**	**6**	**403**

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 billion, which will be incurred between 2018 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2017, the Corporation had provided a surety bond in the amount of US$139 million (2016 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2017, the Corporation had provided letters of credit in the amount of $120 million (2016 - $117 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(I).

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		**2017**			2016	
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**27**	**27**	**2.8%**	—	—	—%
Debentures	**1,046**	**1,051**	**6.0%**	1,045	1,051	6.0%
Senior notes(3)	**1,499**	**1,510**	**6.0%**	2,151	2,158	5.0%
Non-recourse(4)	**1,022**	**1,032**	**4.3%**	1,038	1,048	4.5%
Other(5)	**44**	**44**	**9.2%**	54	54	9.2%
	3,638	**3,664**		4,288	4,311	
Finance lease obligations	**69**			73		
	3,707			4,361		
Less: current portion of long-term debt	**(729)**			(623)		
Less: current portion of finance lease obligations	**(18)**			(16)		
Total current long-term debt and finance lease obligations	**(747)**			(639)		
Total credit facilities, long-term debt, and finance lease obligations	**2,960**			3,722		

(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, 2017 - US$1.2 billion (Dec. 31, 2016 - US$1.6 billion).
(4) Includes US$27 million at Dec. 31, 2017 (Dec. 31, 2016 - US$53 million).
(5) Includes US$24 million at Dec. 31, 2017 (Dec. 31, 2016 - US$29 million) of tax equity financing.

Credit facilities are comprised of the Corporation's $1.0 billion committed syndicated bank credit facility, TransAlta Renewables $0.5 billion committed syndicated bank credit facility, and the Corporation's US$200 million and $240 million committed bilateral facilities. These facilities expire in 2021, 2021, 2020, and 2019 respectively. The $1.5 billion (Dec. 31, 2016 - $1.5 billion) committed syndicated bank facilities are 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, US LIBOR, or US base rate -in accordance with a pricing grid that is standard for such facilities.

During 2017:

- TransAlta Renewables entered into a syndicated credit agreement giving it access to a $0.5 billion committed credit facility. The agreement is fully committed for four years, expiring in 2021. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate -in accordance with a pricing grid that is standard for such facilities. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the new credit agreement, the $350 million credit facility provided by TransAlta was cancelled. The Corporation's consolidated liquidity remains unchanged, as the Corporation's credit facility decreased by $0.5 billion to $1.0 billion in total, while TransAlta Renewables' facility increased to a total of $0.5 billion; and
- the Corporation extended its four-year revolving $1.0 billion committed syndicated credit facility and three bilateral credit facilities by one year to 2021 and 2019, respectively, with key terms and covenants unchanged.

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.

The Corporation has a total of $2.0 billion (Dec. 31, 2016 - $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $500 million. In total, $1.4 billion (Dec. 31, 2016 - $1.4 billion) is not drawn. At Dec. 31, 2017, the $0.6 billion (Dec. 31, 2016 - $0.6 billion) of credit utilized under these facilities was comprised of actual drawings of nil (Dec. 31, 2016 - nil) and letters of credit of $0.6 billion (Dec. 31, 2016 - $0.6 billion). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.4 billion available under the credit facilities, the Corporation also has $314 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 4.5 per cent to 6.9 per cent and have maturity dates ranging from 2018 to 2040.

During 2017, the Corporation's US$400 million 1.90 per cent senior note matured and was paid out using existing liquidity. The repayment was hedged with a currency swap. The maturity value of the bond was $434 million.

A total of US$480 million (2016 - US$630 million) of the senior notes has been designated as a hedge of the Corporation's net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 5.36 per cent.

TransAlta Renewables closed a $260 million non-recourse bond offering on Oct. 2, 2017, by way of a private placement. At the same time, the Corporation early redeemed the $191 million face value CHD non-recourse debentures on Oct. 12, 2017. See Note 4(F) for further details.

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(M));
- the Corporation made a scheduled semi-annual $4 million principal payment on the New Richmond Wind L.P. bond;
- the Corporation made scheduled semi-annual principal payments of approximately $35 million on the Melancthon Wolfe Wind L.P. bond;
- the Corporation's subsidiary TAPC Holdings LP 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(J)), and;
- early redeemed $10 million of non-recourse bonds, which resulted in a $1 million loss recognized in interest expense.

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(P)).

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2017, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP, and Mass Solar non-recourse bonds of $1,022 million (Dec. 31, 2016 - $845 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the 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. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2018. At Dec. 31, 2017, $35 million (Dec. 31, 2016 -$24 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2017. However, as at Dec. 31, 2017, $1 million of cash was on deposit for certain reserve accounts that do not allow the use of letter of credits and was not available for general use.

C. Security

Non-recourse debts of $848 million in total (Dec. 31, 2016 - $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 certain renewable generation facilities with total carrying amounts of $1,107 million at Dec. 31, 2017 (Dec. 31, 2016 - $956 million). At Dec. 31, 2017, a non-recourse bond of approximately $174 million (Dec. 31, 2016 - $201 million) is secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

D. Principal Repayments

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Principal repayments(1)	730	469	472	100	581	1,312	3,664

(1) Excludes impact of derivatives.

E. Restricted Cash

The Corporation has $30 million of proceeds from the KHWLP project financing which is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, including commissioning of the Kent Hills 3 wind project.

F. Finance Lease Obligations

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

As at Dec. 31	2017		2016	
	Minimum lease payments	Present value of minimum lease payments	Minimum lease payments	Present value of minimum lease payments
Within one year	**20**	**20**	19	19
Second to fifth years inclusive	**43**	**38**	44	39
More than five years	**15**	**11**	21	15
	78	**69**	84	73
Less: interest costs	**9**	**—**	11	—
Total finance lease obligations	**69**	**69**	73	73

Included in the Consolidated Statements of Financial Position as:	2017	2016
Current portion of finance lease obligations	**18**	16
Long-term portion of finance lease obligations	**51**	57
	69	73

G. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities, and its uncommitted $100 million demand letter of credit facility. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $100 million demand letter of credit facility.

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, 2017, was $677 million (2016 - $566 million) with no (2016 - 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	2017	2016
Defined benefit obligation *(Note 27)*	**235**	208
Deferred coal revenues	**60**	62
Long-term incentive accruals *(Note 26)*	**16**	14
Other	**48**	46
Total	**359**	330

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 $9 million (2016 - $10 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	2017		2016	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**287.9**	**3,095**	284.0	3,077
Issued under the dividend reinvestment and share purchase plan	**—**	**—**	3.9	18
	287.9	**3,095**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**(1)**	—	(1)
Issued and outstanding, end of year	**287.9**	**3,094**	287.9	3,094

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, 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	**2017**	2016	2015
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Basic and diluted weighted average number of common shares outstanding (millions)	**288**	288	280
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.66)**	0.41	(0.09)

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. 30, 2017, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2018.

On Feb. 2, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Apr. 1, 2018.

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	2017		2016	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	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 E Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Sept. 17, 2017, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017 to, but excluding, Sept. 30, 2022, will be 5.194 per cent, which is equal to the five-year Government of Canada bond yield of 1.544 per cent, determined as of Aug. 31, 2017, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

II. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 16, 2017, the Corporation announced that after, taking into account all election notices received by the June 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017 to, but excluding, June 30, 2022, will be 4.027 per cent, which is equal to the five-year Government of Canada bond yield of 0.927 per cent, determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

III. 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, 2017.

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.

IV. 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, 2017, 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	0.67725	March 31, 2021	2.03	B
B	Floating	0.7255	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.2985	Sept. 30, 2022	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 2017, 2016, and 2015:

	Total dividends declared ($)		
Series	**2017**	2016	2015
A	**5**	10	14
B	**1**	1	—
C	**9**	16	13
E	**8**	14	11
G	**7**	11	8
Total for the year	**30**	52	46

On Feb. 2, 2018, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.17889 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.33125 per share on the Series G preferred shares, all payable on March 31, 2018.

25. Accumulated Other Comprehensive Income

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

	2017	2016
Currency translation adjustment		
Opening balance, Jan. 1	**(1)**	52
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax[1]	**(89)**	(71)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax[2]	**64**	18
Balance, Dec. 31	**(26)**	(1)
Cash flow hedges		
Opening balance, Jan. 1	**456**	350
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[3]	**106**	106
Balance, Dec. 31	**562**	456
Employee future benefits		
Opening balance, Jan. 1	**(38)**	(46)
Net actuarial gains (losses) on defined benefit plans, net of tax[4]	**(6)**	8
Balance, Dec. 31	**(44)**	(38)
Other		
Opening balance, Jan. 1	**(18)**	(3)
Change in ownership of TransAlta Renewables	**4**	—
Intercompany available-for-sale investments	**11**	(15)
Balance, Dec. 31	**(3)**	(18)
Accumulated other comprehensive income	**489**	399

(1) Net of income tax of 11 million for the year ended Dec. 31, 2017 (2016 - 11 million).
(2) Net of income tax of 4 million for the year ended Dec. 31, 2017 (2016 - 5 million).
(3) Net of income tax of 108 million for the year ended Dec. 31, 2017 (2016 - 51 million).
(4) Net of income tax of 4 million for the year ended Dec. 31, 2017 (2016 - 4 million).

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.

The pre-tax compensation expense related to PSUs and RSUs in 2017 was $15 million (2016 - $17 million , 2015 - $3 million reversal), 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 $1 million in 2017 (2016 - $3 million, 2015 - $2 million reversal).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 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 March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance. 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 these grants during 2017 was approximately $1 million (2016 - less than $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2017, are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	Number of options at Dec. 31, 2017	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 8.00	1.9	5.6	6.46
22.00 - 30.00[1]	0.5	2.1	23.60
31.00 - 48.00[1]	0.5	0.1	34.35
5.00 - 48.00	**2.9**	**4.0**	**14.26**

(1) Options currently exercisable.

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, 2017, amounts receivable from employees under the plan totalled less than $1 million (2016 - $1 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 US 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 non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015 and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec .31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2017. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. 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, 2017.

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 US 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 posted a letter of credit in March 2017 for the amount of $77 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 US plans were as at Dec. 31, 2016, and Jan. 1, 2017, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2017.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 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, 2017	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**1**	**10**
Administration expenses	**2**	**—**	**—**	**2**
Interest cost on defined benefit obligation	**20**	**3**	**1**	**24**
Interest on plan assets	**(15)**	**—**	**—**	**(15)**
Defined benefit expense	**14**	**5**	**2**	**21**
Defined contribution expense	**11**	**—**	**—**	**11**
Net expense	**25**	**5**	**2**	**32**

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)
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 initiative described in Note 4(S).

C. Status of Plans

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

As at Dec. 31, 2017	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**416**	**12**	**—**	**428**
Present value of defined benefit obligation	**(561)**	**(87)**	**(27)**	**(675)**
Funded status - plan deficit	**(145)**	**(75)**	**(27)**	**(247)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(4)**	**(6)**	**(2)**	**(12)**
Other long-term liabilities	**(141)**	**(69)**	**(25)**	**(235)**
Total amount recognized	**(145)**	**(75)**	**(27)**	**(247)**

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)

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**
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 US plans	(1)	—	—	(1)
As at Dec. 31, 2016	423	10	—	433
Interest on plan assets	**15**	**—**	**—**	**15**
Net return on plan assets	**26**	**—**	**—**	**26**
Contributions	**6**	**6**	**—**	**12**
Benefits paid	**(51)**	**(4)**	**—**	**(55)**
Administration expenses	**(2)**	**—**	**—**	**(2)**
Effect of translation on US plans	**(1)**	**—**	**—**	**(1)**
As at Dec. 31, 2017	**416**	**12**	**—**	**428**

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

Year ended Dec. 31, 2017	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**76**	**—**	**76**
US	**—**	**31**	**—**	**31**
International	**—**	**118**	**—**	**118**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**43**	**—**	**43**
AA	**—**	**71**	**—**	**71**
A	**—**	**44**	**—**	**44**
BBB	**1**	**25**	**—**	**26**
Below BBB	**—**	**5**	**—**	**5**
Money market and cash and cash equivalents	**(1)**	**14**	**—**	**13**
Total	**—**	**427**	**1**	**428**

Year ended Dec. 31, 2016	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	76	—	76
US	—	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

Plan assets do not include any common shares of the Corporation at Dec. 31, 2017, and Dec. 31, 2016. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2017 (2016 - $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, 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 gain arising from demographic assumptions	(1)	–	(4)	(5)
Actuarial loss arising from financial assumptions	2	–	–	2
Actuarial gain (loss) arising from experience adjustments	–	2	(2)	–
Effect of translation on US plans	(1)	–	(1)	(2)
Present value of defined benefit obligation as at Dec. 31, 2016	**554**	**82**	**27**	**663**
Current service cost	**7**	**2**	**1**	**10**
Interest cost	**20**	**3**	**1**	**24**
Benefits paid	**(51)**	**(4)**	**–**	**(55)**
Actuarial loss arising from demographic assumptions	**4**	**1**	**–**	**5**
Actuarial loss arising from financial assumptions	**26**	**3**	**–**	**29**
Actuarial (gain) loss arising from experience adjustments	**3**	**–**	**(1)**	**2**
Effect of translation on US plans	**(2)**	**–**	**(1)**	**(3)**
Present value of defined benefit obligations as at Dec. 31, 2017	**561**	**87**	**27**	**675**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2017 is 14.6.

F. Contributions

The expected employer contributions for 2018 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**4**	**6**	**2**	**12**

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, 2017			As at Dec. 31, 2016		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.3**	**3.3**	**3.4**	3.7	3.6	3.7
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health care cost trend rate						
Health care cost escalation	**—**	**—**	**7.8**(1)	—	—	7.9(3)
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.7**	**3.6**	**3.7**	3.8	3.8	3.8
Rate of compensation increase	**2.6**	**3.0**	**—**	3.0	3.0	—
Assumed health care cost trend rate						
Health care cost escalation	**—**	**—**	**7.9**(2)	—	—	7.8(4)
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health care premium escalation	**—**	**—**	**—**	—	—	5.0

(1) Post- and Pre 65 rates: decreasing gradually to 4.5% by 2027 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 2026 and remaining at that level thereafter for the U.S. and decreasing gradually by 0.30% per year to 5% in 2024 for Canada.
(3) 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 0.30% per year to 5% in 2024 for Canada.
(4) Post- and Pre 65 rates: decreasing gradually to 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.

H. Sensitivity Analysis

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

	Canadian plans			US plans	
Year ended Dec. 31, 2017	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**79**	**12**	**3**	**3**	**1**
1% increase in the salary scale	**10**	**1**	**—**	**—**	**—**
1% increase in the health care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**2**	**—**	**1**	**—**

28. Joint Arrangements

Joint arrangements at Dec. 31, 2017, 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
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

29. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2017**	2016	2015
(Use) source:			
Accounts receivable	**(228)**	(23)	(77)
Prepaid expenses	**(75)**	5	(3)
Income taxes receivable	**8**	(4)	1
Inventory	**(7)**	11	(9)
Accounts payable, accrued liabilities, and provisions	**186**	81	(152)
Income taxes payable	**2**	3	(2)
Change in non-cash operating working capital	**(114)**	73	(242)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2016	Cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2017
Long-term debt and finance lease obligations	4,361	(545)	14	—	(115)	(8)	3,707
Dividends payable (common and preferred)	54	(86)	—	64	—	2	34
Total liabilities from financing activities	**4,415**	**(631)**	**14**	**64**	**(115)**	**(6)**	**3,741**

30. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2017	2016	Increase/ (decrease)
Long-term debt(1)	**3,707**	4,361	**(654)**
Equity			
Common shares	**3,094**	3,094	**—**
Preferred shares	**942**	942	**—**
Contributed surplus	**10**	9	**1**
Deficit	**(1,209)**	(933)	**(276)**
Accumulated other comprehensive income	**489**	399	**90**
Non-controlling interests	**1,059**	1,152	**(93)**
Less: available cash and cash equivalents(2)	**(314)**	(305)	**(9)**
Less: fair value asset of hedging instruments on long-term debt(3)	**(30)**	(163)	**133**
Total capital	**7,748**	8,556	**(808)**

(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 economic and designated 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 and 2017, 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, 2016, 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 Standard & Poor's (negative outlook), DBRS (stable outlook) and Fitch Ratings (stable outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook. During 2017, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- and changed their outlook from negative to stable, DBRS changed the Corporation's Unsecured Debt rating and Medium-Term Notes rating from BBB to BBB (low), the Preferred Shares rating from Pfd-3 to Pfd-3 (low), and Issuer Rating from BBB to BBB (low) (with outlook changed to stable from negative), and Standard & Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB-, but changed the outlook from stable to negative. 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	2017	2016	Target
Comparable funds from operations to adjusted interest coverage (times)	**4.3**	3.9	4 to 5
Adjusted comparable funds from operations to adjusted net debt (%)	**20.4**	16.3	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation, and amortization (times)	**3.6**	3.8	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 2017 improved compared with 2016. 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 2017 compared to 2016 due to the increase in comparable FFO, and lower debt due to repayments. 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 2017 improved compared to 2016 due to the lower debt balance due to repayments. 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 2017, 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. In 2016, the Corporation reduced its 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 years ended Dec. 31, 2017 and 2016, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2017	2016	Increase (decrease)
Cash flow from operating activities	**626**	744	(118)
Change in non-cash working capital	**114**	(73)	187
Cash flow from operations before changes in working capital	**740**	671	69
Dividends paid on common shares	**(46)**	(69)	23
Dividends paid on preferred shares	**(40)**	(42)	2
Distributions paid to subsidiaries' non-controlling interests	**(172)**	(151)	(21)
Property, plant, and equipment expenditures(1)	**(338)**	(358)	20
Inflow	**144**	51	223

(1) Includes growth capital associated with the South Hedland Power Station.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2017, $1.4 billion (2016 - $1.4 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.

31. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2017 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	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	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	2017	2016	2015
Total compensation	**24**	20	9
Comprised of:			
Short-term employee benefits	**14**	8	8
Post-employment benefits	**2**	2	2
Termination benefits	**—**	—	1
Share-based payments	**8**	10	(2)

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:

	2018	2019	2020	2021	2022	2023 and thereafter	Total
Natural gas, transportation, and other purchase contracts	48	7	5	5	4	29	**98**
Transmission	9	6	6	3	—	—	**24**
Coal supply and mining agreements	155	159	161	23	14	96	**608**
Long-term service agreements	108	50	41	31	15	35	**280**
Non-cancellable operating leases(1)	9	9	9	9	9	111	**156**
Growth	27	—	—	—	—	—	**27**
TransAlta Energy Transition Bill	6	6	6	6	6	6	**36**
Total	**362**	**237**	**228**	**77**	**48**	**277**	**1,229**

(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 purchase contracts relate to commitments for goods and services.

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 with dates extending to 2020.

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 commitments have been reduced, due to 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, 2017, $7 million (2016 - $9 million, 2015 - $9 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2017 and 2016 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 relate to the construction of the Kent Hills 3 wind project.

G. TransAlta Energy Transition Bill Commitments
On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining 9 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, 2017, the Corporation has funded approximately US$28 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 has been participating in a line loss rule proceeding (the "LLRP") before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the Alberta Electric System Operator to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA MWs. The estimate of the maximum exposure is $15 million; however, if the Corporation and others are successful on the appeal of legal and jurisdictional questions regarding retroactivity, the amount owing will be nil. The Corporation has therefore recorded a provision of $7.5 million.

II. FMG Disputes

The Corporation is currently engaged in litigation with FMG as a result of their purported termination of the South Hedland PPA. In addition, FMG withheld approximately AUD$58.2 million, including AUD$43 million in tax applicable to the repurchase of the Solomon Power Station. TransAlta is seeking payment of all withheld amounts, and has currently commenced proceedings to recover approximately AUD$54.1 million by filing and serving FMG with a Writ and Statement of Claim on Nov. 17, 2017, and also applied for summary judgment for this amount. The hearing is scheduled for March 23, 2018.

33. Segment Disclosures

A. Description of Reportable Segments

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

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec 31, 2017	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Revenues	**999**	**435**	**261**	**135**	**287**	**121**	**69**	**—**	**2,307**
Fuel and purchased power	**585**	**293**	**101**	**14**	**17**	**6**	**—**	**—**	**1,016**
Gross margin	**414**	**142**	**160**	**121**	**270**	**115**	**69**	**—**	**1,291**
Operations, maintenance, and administration	**192**	**51**	**50**	**31**	**48**	**37**	**24**	**84**	**517**
Depreciation and amortization	**317**	**73**	**38**	**37**	**111**	**31**	**2**	**26**	**635**
Asset impairment charge	**20**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**20**
Taxes, other than income taxes	**13**	**4**	**1**	**—**	**8**	**3**	**—**	**1**	**30**
Net other operating income	**(40)**	**—**	**(9)**	**—**	**—**	**—**	**—**	**—**	**(49)**
Operating income (loss)	**(88)**	**14**	**80**	**53**	**103**	**44**	**43**	**(111)**	**138**
Finance lease income	**—**	**—**	**11**	**43**	**—**	**—**	**—**	**—**	**54**
Net interest expense									**(247)**
Foreign exchange loss									**(1)**
Gain on sale of assets and other									**2**
Losses before income taxes									**(54)**

Year ended Dec 31, 2016	Canadian Coal	US 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 charge	—	—	—	—	28	—	—	—	28
Restructuring provision	—	—	—	—	—	—	—	1	1
Taxes, other than income taxes	13	4	1	1	8	3	—	1	31
Net other operating (income) loss	(2)	—	(191)	—	(1)	—	—	—	(194)
Operating income (loss)	166	(46)	253	56	48	49	49	(97)	478
Finance lease income	—	—	14	52	—	—	—	—	66
Net interest expense									(229)
Foreign exchange loss									(5)
Gain on sale of assets									4
Earnings before income taxes									314

Year ended Dec 31, 2015	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	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 reversals	—	(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) losses	(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

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2017 is $18 million (2016 -$19 million, 2015 - $20 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 $247 million for the year ended Dec. 31, 2017 (2016 - $221 million, 2015 - $230 million).

II. Selected Consolidated Statements of Financial Position Information

As at Dec 31, 2017	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	—	—	—	—	**174**	**259**	**30**	—	**463**
PP&E	**2,902**	**370**	**416**	**606**	**1,764**	**497**	**1**	**22**	**6,578**
Intangible assets	**91**	**7**	**3**	**42**	**149**	**3**	**13**	**56**	**364**

As at Dec 31, 2016	Canadian Coal	US 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
Intangibles	93	7	4	12	163	3	15	58	355

III. Selected Consolidated Statements of Cash Flows Information
Additions to non-current assets are as follows:

Year ended Dec 31, 2017	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**116**	**35**	**31**	**114**	**20**	**16**	**—**	**6**	**338**
Intangible assets	**5**	**1**	**—**	**29**	**—**	**—**	**—**	**16**	**51**

Year ended Dec 31, 2016	Canadian Coal	US 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
Intangibles	3	1	1	—	—	—	—	16	21

Year ended Dec 31, 2015	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	179	13	19	204	13	43	1	4	476
Intangibles	6	—	—	—	—	—	3	17	26

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	**2017**	2016	2015
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**635**	601	545
Depreciation included in fuel and purchased power *(Note 5)*	**73**	63	59
Loss on disposal of property, plant, and equipment	**—**	—	1
Depreciation and amortization on the Consolidated Statements of Cash Flows	**708**	664	605

C. Geographic Information
I. Revenues

Year ended Dec. 31	**2017**	2016	2015
Canada	**1,663**	1,828	1,705
US	**509**	450	448
Australia	**135**	119	114
Total revenue	**2,307**	2,397	2,267

II. Non-Current Assets

	Property, plant, and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Canada	**5,353**	5,583	**297**	315	**105**	184	**417**	417
US	**619**	714	**25**	28	**43**	42	**46**	47
Australia	**606**	527	**42**	12	**89**	16	**—**	—
Total	**6,578**	6,824	**364**	355	**237**	242	**463**	464

D. Significant Customer

During the year ended Dec. 31, 2017, sales to one customer represented 28 per cent, of the Corporation’s total revenue (2016 - two customers representing 25 per cent and 16 per cent, respectively).

34. Subsequent Events

A. Normal Course Issuer Bid

On March 1, 2018, the Corporation announced that it intends to seek Toronto Stock Exchange ("TSX") acceptance of a normal course issuer bid ("NCIB"). The Board has authorized the repurchases of up to 14,000,000 of its common shares, representing approximately five per cent of TransAlta's public float. Purchases under the NCIB are expected to be made through open market transactions on the TSX and any alternative Canadian trading platforms, based on the prevailing market price. Any Common Shares purchased under the NCIB will be cancelled.

B. Early Redemption of Senior Notes Due 2018

On Feb. 2, 2018, the Corporation announced it called for the redemption of its outstanding US$500 million 6.65 per cent senior notes maturing May 15, 2018 (the “Senior Notes”). The Senior Notes will be redeemed on March 15, 2018, at a price equal to the greater of: i) 100 per cent of the principal amount of the Senior Notes and ii) the sum of the present values of the remaining scheduled payments of principal and interest thereon discounted to the redemption date on a semi-annual basis at the treasury rate plus 45 basis points, plus in each case, accrued interest thereon to the date of redemption.

C. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it entered into an arrangement to acquire two construction-ready projects in the Northeastern United States.

The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA and ii) a 29 MW project located in New Hampshire with two 20-year PPAs. All three counterparties have Standard & Poor's credit ratings of A+ or better.

The total cost of the two projects is estimated to be US$240 million, of which approximately 70% will be funded in 2018 and the remainder in 2019. The commercial operation date for both projects is expected during the second half of 2019.

TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity.

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, 2017:

Earnings coverage on long-term debt supporting the Corporation's Shelf Prospectus

0.57 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	**2017**	2016	2015
Financial Summary			
Statement of Earnings			
Revenues	**2,307**	2,397	2,267
Operating income	**138**	478	148
Net earnings (loss) attributable to common shareholders	**(190)**	117	(24)
Statement of Financial Position			
Total assets	**10,304**	10,996	10,947
Current portion of long-term debt, net of cash and cash equivalents	**433**	334	33
Credit facilities, long-term debt and finance lease obligations	**2,960**	3,722	4,408
Non-controlling interests	**1,059**	1,152	1,029
Preferred shares	**942**	942	942
Equity attributable to common shareholders	**2,384**	2,569	2,419
Fair value (asset) liability of hedging instruments on debt	**(30)**	(163)	(190)
Total invested capital(1)	**7,748**	8,556	8,641
Cash Flows			
Cash flow from operating activities	**740**	744	432
Cash flow from (used in) investing activities	**87**	(327)	(573)
Common Share Information *(per share)*			
Net earnings (loss)	**(0.66)**	0.41	(0.09)
Comparable earnings(2)	**n/a**	0.13	(0.17)
Dividends paid on common shares	**0.16**	0.30	0.72
Book value per common share *(at year-end)*	**8.28**	8.92	8.52
Market price:			
High	**8.50**	7.54	12.34
Low	**6.88**	3.76	4.13
Close *(Toronto Stock Exchange at Dec. 31)*	**7.45**	7.43	4.91
Ratios *(percentage except where noted)*			
Adjusted net debt to invested capital	**49.5**	51.0	54.6
Adjusted net debt to invested capital excluding non-recourse debt	**41.8**	44.2	50.2
Adjusted net debt to comparable EBITDA *(times)*(2)(5)	**3.6**	3.8	5.4
Return on equity attributable to common shareholders	**(10.0)**	5.4	(1.2)
Comparable return on equity attributable to common shareholders(2)	**n/a**	1.7	(2.3)
Return on capital employed	**2.1**	5.3	4.6
Comparable return on capital employed(2)	**n/a**	4.4	3.0
Earnings coverage *(times)*	**0.6**	1.7	1.5
Dividend payout ratio based on comparable funds from operations(2)(5)	**4.3**	8.1	30.0
Comparable EBITDA *(in millions of Canadian dollars)*(2)(5)	**1,062**	1,144	867
Dividend coverage *(times)*(2)(5)	**14.1**	11.1	3.3
Dividend yield	**2.1**	4.0	14.7
Adjusted comparable funds from operations to adjusted net debt(2)(5)	**20.4**	16.3	14.3
Comparable funds from operations before interest to adjusted interest coverage *(times)*(2)(5)	**4.3**	3.9	3.7
Weighted average common shares for the year *(in millions)*	**288**	288	280
Common shares outstanding at Dec. 31 *(in millions)*	**288**	288	284
Statistical Summary			
Number of employees	**2,228**	2,341	2,380
Generating capacity *(MW)*(3)			
Coal (Canadian and US)	**5,131**	5,131	5,126
Gas(4)	**1,403**	1,482	1,405
Renewables (wind, solar and hydro)	**2,289**	2,334	2,350
Equity investments	**-**	-	-
Total generating capacity	**8,823**	8,947	8,881
Total generation production *(GWh)*	**36,900**	38,157	40,673

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. For 2017, comparable earnings measures are no longer being calculated or reported on.

(3) 2017, 2016, 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.

(5) 2016 and 2015 revised due to revisions to EBITDA or FFO measures in MD&A.

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")

2014	2013	2012	2011	2010	2009	2008	2007
2,623	2,292	2,210	2,618	2,673	2,770	3,110	2,775
442	195	(214)	645	487	378	533	541
141	(71)	(615)	290	255	181	235	309
9,833	9,624	9,503	9,780	9,635	9,762	7,815	7,157
708	175	582	284	202	(51)	194	600
3,305	4,130	3,610	3,721	3,823	4,411	2,564	1,837
594	517	330	358	431	478	469	496
942	781	–	–	–	–	–	–
2,342	2,125	3,018	3,274	3,120	2,929	2,510	2,299
(96)	(16)	50	32	41	16	–	–
7,795	7,712	7,590	7,669	7,617	7,783	5,737	5,232
796	765	520	690	838	580	1,038	847
(292)	(703)	(1,048)	(608)	(765)	(1,598)	(581)	(410)
0.52	(0.27)	(2.62)	1.31	1.16	0.90	1.18	1.53
0.25	0.31	0.50	1.05	0.97	0.90	1.46	1.31
0.83	1.16	1.16	1.16	1.16	1.16	1.08	1.00
8.52	7.92	8.78	12.08	12.85	13.41	12.70	11.39
14.94	16.86	21.37	23.24	23.98	25.30	37.50	34.00
9.81	12.91	14.11	19.45	19.61	18.11	21.00	23.79
10.52	13.48	15.12	21.02	21.15	23.48	24.30	33.35
56.3	60.7	61.0	52.5	53.1	56.1	48.1	46.8
54.1	58.7	59.0	60.0	50.7	52.6	45.6	44.0
4.2	4.6	4.6	3.8	–	–	–	–
6.3	(3.2)	(25.9)	10.6	9.6	6.9	9.4	13.1
3.0	3.7	4.9	8.4	8.0	6.9	11.6	10.5
5.8	2.8	(3.1)	8.3	6.6	5.7	7.7	9.8
5.1	5.2	5.3	7.0	6.0	5.8	9.6	9.7
1.7	0.8	(1.0)	2.7	2.2	1.9	2.8	3.3
26.4	43.1	25.1	24.0	39.6	–	–	–
1,036	1,023	1,015	1,044	955	888	1,006	980
5.7	6.3	4.7	3.5	4.0	2.6	4.8	4.2
7.9	8.6	7.7	5.5	5.5	4.9	4.4	3.0
16.9	15.2	16.7	20.1	19.6	20.5	31.7	30.7
3.8	3.7	3.3	4.4	4.6	4.9	7.2	6.6
273	264	235	222	219	201	199	202
275	268	255	224	220	218	198	201
2,786	2,772	2,084	2,235	2,389	2,343	2,200	2,201
5,111	5,111	4,551	4,325	4,688	4,967	4,942	4,942
1,531	1,779	1,731	1,567	1,648	1,843	1,913	1,960
2,204	2,202	2,058	1,974	1,950	1,965	1,218	1,122
–	396	390	390	390	–	–	–
8,846	9,488	8,730	8,256	8,676	8,775	8,073	8,024
45,002	42,482	38,750	41,012	48,614	45,736	48,891	50,395

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

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

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

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

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

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

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

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

Plant Summary

As of January 2018	Facility*	Installed capacity (MW)[1]	Ownership (%)	Owned capacity (MW)[1][2]	Region	Revenue source	Contract expiry date
Coal 6 Facilities	Sundance, AB	1,861	100%	1,861	Western Canada	Alberta PPA[3]/ Merchant[4]	2018
	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		**5,710**		**4,653**			
Gas 12 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
	Parkeston, WA*[11]	110	50%	55	Australia	LTC	2026
Total Gas		**1,613**		**1,348**			
Wind 20 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	-
	Castle River, AB*[13]	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*[14]	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*[14]	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		**1,417**		**1,318**			
Solar 1 Facility	Mass Solar, MA[15]	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		**9,709**		**8,266**			

* 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, 2017, TransAlta owns approximately 64% of the outstanding shares of TransAlta Renewables.
(3) PPA refers to Power Purchase Arrangement to be terminated on March 31, 2018.
(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) Includes seven individual turbines at other locations.
(14) Comprised of two facilities.
(15) Comprised of four ground-mounted projects and four roof-top projects.

Sustainability Performance Indicators

Corporate Statistics

Environment, Health and Safety Management Systems	2017	2016	2015
Facilities with ISO 14001 and/or OHSAS 18001-based management systems *(percentage)*[1]	**97**	97	97
Management system audits[2]	**20**	35	23

Environmental Performance	2017	2016	2015
Resource or Energy Use[3]			
Coal combustion *(tonnes)*	**14,956,400**	15,735,300	16,222,300
Natural gas combustion *(GJ)*	**55,520,900**	62,486,700	63,411,200
Diesel combustion *(L)*	**4,384,700**	46,179,400	22,565,800
Gasoline consumption: vehicle *(L)*	**1,476,700**	1,487,200	1,376,300
Diesel consumption: vehicle *(L)*	**44,045,200**	40,224,800	43,183,000
Propane consumption: vehicle *(L)*	**112,000**	78,800	113,600
Electricity: building operations *(MWh)*	**290,100**	359,300	220,800
Natural gas: building operations *(GJ)*	**75,500**	58,300	58,500
Propane: building operations *(L)*	**125,800**	127,500	102,700
Kerosene: building operations *(L)*	**96,200**	56,500	60,100
Total resource or energy use *(GJ)*[4]	**496,910,700**	528,442,794	542,362,600
Greenhouse Gas Emissions[5]			
Carbon dioxide *(tonnes CO_2e)* ✓	**29,627,700**	30,381,300	31,902,700
Methane *(tonnes CO_2e)* ✓	**107,100**	114,200	112,600
Nitrous oxide *(tonnes CO_2e)* ✓	**190,900**	224,600	212,400
Sulphur hexafluoride *(tonnes CO_2e)*	**10**	20	20
Total greenhouse gas emissions *(tonnes CO_2e)*[6] ✓	**29,925,600**	30,720,100	32,227,800
Greenhouse gas emission intensity *(tonnes CO_2e/MWh)*[7] ✓	**0.86**	0.83	0.87
Air Emissions[8]			
Total sulphur dioxide emissions *(tonnes)* ✓	**36,200**	39,600	41,800
Sulphur dioxide emission intensity *(kg/MWh)*[9] ✓	**1.05**	1.08	1.13
Total nitrogen oxide emissions *(tonnes)* ✓	**44,400**	48,400	48,000
Nitrogen oxide emission intensity *(kg/MWh)*[9] ✓	**1.28**	1.33	1.30
Total particulate matter emissions *(tonnes)* ✓	**5,000**	4,900	4,900
Particulate matter emission intensity *(kg/MWh)*[9] ✓	**0.14**	0.13	0.13
Total mercury emissions *(kilograms)* ✓	**110**	130	170
Mercury emission intensity *(mg/MWh)*[9] ✓	**3.29**	3.52	4.50
Water Management[10]			
Water intake *(million m^3)* ✓	**213**	239	258
Water discharge *(million m^3)* ✓	**172**	197	212
Water consumption *(million m^3)* ✓	**41**	42	46
Water intensity *(m^3/MWh)*[11] ✓	**1.18**	1.63	1.24
Waste Management[12]			
Non-Hazardous			
Landfill *(tonnes)* ✓	**3,200**	2,100	2,400
Landfill *(L)* ✓	**63,500**	518,400	131,200
Ash disposal: mine *(tonnes)*[13] ✓	**1,338,600**	1,315,000	1,346,900
Ash disposal: lagoon *(tonnes)*[14] ✓	**485,500**	527,700	501,600
Recycled *(tonnes)* ✓	**1,400**	18,000	151,100
Recycled *(L)* ✓	**4,122,700**	212,100	222,100
Reuse *(tonnes)* ✓	**827,400**	700,700	707,800
Storage *(tonnes)* ✓	**0**	8,300	14,800

Environmental Performance *(continued)*	2017	2016	2015
Waste Management *(continued)*			
Hazardous[15]			
Landfill *(tonnes)* ✓	**40**	40	40
Landfill *(L)* ✓	**14,600**	13,110	3,300
Recycled *(tonnes)* ✓	**12,740**	60	80
Recycled *(L)* ✓	**20,140,400**	17,209,560	536,100
Land Use and Reclamation[16]			
Land used in mining activities: disturbed *(cumulative hectares)* ✓	**12,100**	11,800	11,700
Land used in mining activities: reclaimed *(cumulative hectares)* ✓	**4,600**	4,600	4,500
Land reclamation *(% of land disturbed)*[17] ✓	**38**	39	39
Land used in mining activities: disturbed minus reclaimed *(hectares)* ✓	**7,400**	7,200	7,200
Land used by plants, offices and equipment *(hectares)* ✓	**3,900**	2,700	2,700
Total land use *(cumulative hectares)* ✓	**11,300**	9,900	9,900
Environmental Incidents			
Total environmental incidents[18] ✓	**5**	16	12
Environmental enforcement actions	**0**	0	1
Environmental fines *($ thousands)*	**0**	0	1.7
Spills[19]			
Volume of significant spills *(m^3)*	**15**	61	19

Social Performance	2017	2016	2015
Workplace Practices			
Employees	**2,228**	2,341	2,380
Number of full-time employees	**2,125**	2,267	2,301
Number of part-time employees	**24**	26	26
Number of contingent employees	**79**	48	53
Employees represented by independent trade union organizations *(%)*[20]	**57**	53	54
Voluntary employee turnover rate *(%)*[21]	**10.65**	6.71	5.22
Diversity			
Women in workforce *(%)*	**19**	18	18
Women in senior management *(%)*	**26**	26	25
Women on Board of Directors *(%)*	**40**	33	30
Health and Safety			
Health and safety enforcement actions[22]	**4**	4	0
Health and safety fines *($ thousands)*	**0**	5.4	0
Employee & contractor fatalities ✓	**0**	0	0
Lost-time injury (LTI) (absence from work) ✓	**6**	4	5
Medical aids (MA) (no absence from work) ✓	**15**	20	20
Total injuries to employees & contractors ✓	**21**	24	25
Total injury frequency rate (IFR) (employees and contractors)[23] ✓	**0.72**	0.85	0.75
Total incident frequency (TIF) (employees and contractors)[24]	**3.54**	3.29	3.04
Reportable vehicle incidents	**35**	33	28
Community Relations			
Community investments *($ millions)*[25]	**2.6**	2.5	3.5

✓ *2017 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 67 facilities.*

(2) *Internal audits conducted against ISO management systems, regulatory frameworks and 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 (GHG) emissions reporting, which is the application of an Operational Control boundary.*

(4) *Our 2016 energy data was revised in 2017, due to changes in our 2016 diesel combustion at our Centralia facility and 2016 natural gas combustion and diesel combustion at our Sarnia facility. Centralia 2016 diesel combustion was misreported in 2016. Sarnia 2016 energy data was misreported due to IT system-related errors. Sarnia 2016 vehicle diesel usage was applied incorrectly. Diesel usage was for a diesel backup generator and volumes were applied to diesel combustion and not diesel consumption from vehicles.*

(5) *Greenhouse gas (GHG) emissions are calculated and reported from TransAlta-operated facilities in line with carbon regulations 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.*

(6) *Gross GHG emissions or gross carbon dioxide equivalent (CO_2e) emissions is the sum of carbon dioxide, methane, nitrous oxide and sulfur hexafluoride. Coincidentally the sum of scope 1 and 2 emissions will equate to gross CO_2e emissions or gross GHG emissions. Our 2016 GHG data was revised in 2017, due to changes in our 2016 diesel combustion at our Centralia facility and 2016 natural gas combustion and diesel combustion at our Sarnia facility. Please see Note 3 for revision explanations.*

(7) *GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. Our Australia 2016 production data was revised in 2017 due to metering issues in 2016. As a result our GHG intensity for 2016 dropped from 0.84 to 0.83 tonnes CO_2e/MWh.*

(8) *Air emissions are reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is the 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.*

(9) *Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*

(10) *Water usage is reported from TransAlta-operated facilities, following the same approach we use for GHG reporting, which is the 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. Sundance 2015 and 2016 historical water data was revised in 2017 due to misalignment in reporting between corporate and business unit data. Water volumes that are discharged to our cooling pond, adjacent to Wabamum Lake, were being applied as intake volumes. These volumes are discharge volumes and have been reallocated accordingly.*

(11) *Water 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.*

(12) *Non-hazardous waste includes, but is not limited to, the disposal of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials.*

(13) *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.*

(14) *Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.*

(15) *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.*

(16) *Total land use is mining land use plus land used by plants, offices and equipment.*

(17) *Disturbed land use Highvale mine volumes were reconciled in 2017 to match Alberta regulatory reporting data. Actual disturbed volumes in 2017 were 160 hectares and these volumes were reconciled with 80 hectares to ensure our total land disturbed volumes align. As a result our land reclamation percentage was down one per cent compared with 2016 data.*

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

(19) *Substances released to the environment include, but are not limited to, ash, glycol, diesel, oils and other chemicals.*

(20) *TransAlta has over 1,200 unionized workers working primarily at our operations.*

(21) *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.*

(22) *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.*

(23) *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.*

(24) *Total incident frequency (TIF) tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids) relative to employee hours worked.*

(25) *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, 2017.

- 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
- 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)
- Land use – disturbed and reclaimed

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, which is responsible for the assertions, statements and claims made therein (including the assertions we have been engaged to provide limited assurance over); the 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 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.

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 1, 2018

Shareholder Information

Annual Meeting
The Annual and Special Meeting of Shareholders will be held at 10:00 a.m. MST, on Friday, April 20, 2018, in the Palomino Room (E-H) at the BMO Centre (Stampede Park) 20 Roundup Way SW, Calgary, Alberta.

Transfer Agent
AST Trust Company (Canada)*
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

Email
inquiries@astfinancial.com

Fax
514.985.8843

Website
www.astfinancial.com/ca-en

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

* *AST Trust Company (Canada), formerly CST Trust Company, changed its name on July 20, 2017. 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 2017

Payment Date	Record Date	Ex-Dividend Date	Dividend
July 1, 2017	June 1, 2017	May 30, 2017	$0.04
Oct. 1, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.04
Jan. 1, 2018	Dec. 1, 2017	Nov. 30, 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 $1.01 per share from and including June 30, 2017, to but excluding June 30, 2022.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.30 per share from and including September 30, 2017, to but excluding Sept. 30, 2022.

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 2017

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2017	June 1, 2017	May 30, 2017	$0.16931
Sept. 30, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.16931
Dec. 31, 2017	Dec. 1, 2017	Nov. 30, 2017	$0.16931

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2017	June 1, 2017	May 30, 2017	$0.15645
Sept. 30, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.16125
Dec. 31, 2017	Dec. 1, 2017	Nov. 30, 2017	$0.17467

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2017	June 1, 2017	May 30, 2017	$0.2875
Sept. 30, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.25169
Dec. 31, 2017	Dec. 1, 2017	Nov. 30, 2017	$0.25169

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2017	June 1, 2017	May 30, 2017	$0.3125
Sept. 30, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.3125
Dec. 31, 2017	Dec. 1, 2017	Nov. 30, 2017	$0.32463

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
June 30, 2017	June 1, 2017	May 30, 2017	$0.33125
Sept. 30, 2017	Sept. 1, 2017	Aug. 30, 2017	$0.33125
Dec. 31, 2017	Dec. 1, 2017	Nov. 30, 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:
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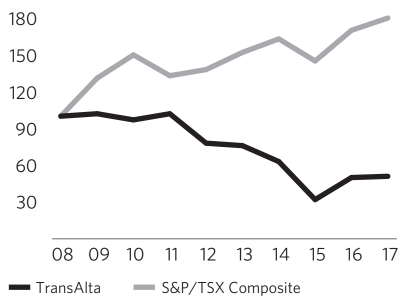
Calgary/outside North America:
403.267.2520

Email
investor_relations@transalta.com

Fax
403.267.7405

Website
www.transalta.com

Shareholder Highlights



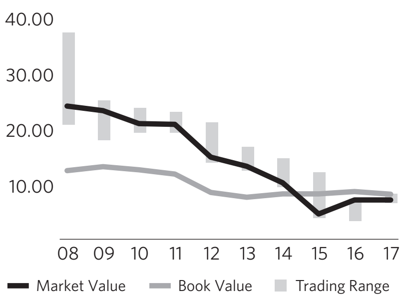
Total Shareholder Return vs. S&P/TSX Composite Index

Year ended Dec. 31 *($)*

	08	09	10	11	12	13	14	15	16	17
TransAlta	100	102	97	102	78	76	63	32	50	51
S&P/TSX Composite	100	131	150	133	138	152	163	145	170	180

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2008 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet



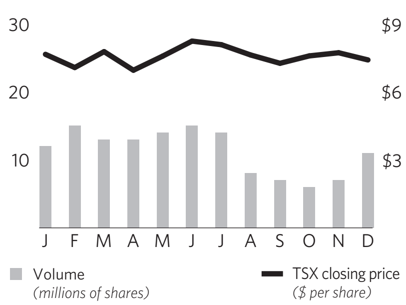
Ten-Year Trading Range and Market Value vs. Book Value

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

	08	09	10	11	12	13	14	15	16	17
Market Value	24.30	23.48	21.15	21.02	15.12	13.48	10.52	4.91	7.43	7.45
Book Value	12.70	13.41	12.85	12.08	8.78	7.92	8.52	8.52	8.92	8.28

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

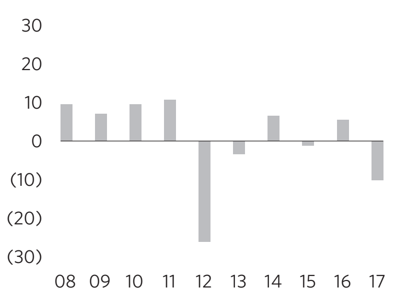


Monthly Volume and Market Prices

(2017)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	12	15	13	13	14	15	14	8	7	6	7	11
TSX closing price	7.70	7.11	7.82	6.99	7.62	8.29	8.13	7.67	7.30	7.63	7.77	7.45

Source: FactSet



Return on Common Shareholders' Equity

(%)

	08	09	10	11	12	13	14	15	16	17
ROE	9.4	6.9	9.6	10.6	(25.9)	(3.2)	6.3	(1.2)	5.4	(10.0)

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 US 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 (US/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

Dawn L. Farrell
President and Chief Executive Officer

Donald Tremblay
Chief Financial Officer

Brett M. Gellner
Chief Investment Officer

Dawn E. de Lima
Chief Administrative Officer

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

Aron J. Willis
Senior Vice-President, Gas & Renewables

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

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

Nipa Chakravarti
Chief Transformation Officer

Todd J. Stack
Managing Director, Corporate Controller

Brent Ward
Managing Director and Treasurer

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 British Thermal Units (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
A term used to describe assets that are not contracted and are exposed to market pricing.

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.

In an effort to be environmentally responsible, please notify your financial institution if you are receiving duplicate mailings of this annual report.

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

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