

# Management's Discussion and Analysis

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*This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our audited annual 2018 consolidated financial statements and our Annual Information Form for the year ended Dec. 31, 2018. 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, 2018. 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 February 26, 2019. 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](http://www.sedar.com), on EDGAR at [www.sec.gov](http://www.sec.gov), and on our website at [www.transalta.com](http://www.transalta.com). Information on or connected to our website is not incorporated by reference herein.*

## Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws, and "forward-looking statements" within the meaning of applicable United States securities laws, including the United States *Private Securities Litigation Reform Act of 1995* (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumption was made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "can", "could", "would", "shall", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "foresee", "potential", "enable", "continue" or other comparable terminology. These statements are not guarantees of our future performance, events or results and are subject to risks, uncertainties and other important factors that could cause our actual performance, events or results to be materially different from that set out in or implied by the forward-looking statements.

In particular, this MD&A contains forward-looking statements including, but not limited to: our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2018 to 2031 and beyond; potential for growth in renewables and greenfield development acquisitions; the amount of capital allocated to new growth or development projects; our business, anticipated future financial performance and anticipated results, including our outlook and performance targets; our expected success in executing on our growth projects; the timing and the completion of growth and development projects, and their attendant costs; our estimated spend on growth and sustaining capital and productivity projects; expectations in terms of the cost of operations, capital spend and maintenance, and the variability of those costs; the conversion of our coal-fired units to natural gas, and the timing and costs thereof; the form and terms of any definitive agreement with Tidewater, as defined below, regarding the construction of a pipeline; the terms of the current or any further proposed normal course issuer bid, including timing and number of shares to be repurchased pursuant to the normal course issuer bid and the acceptance thereof by the Toronto Stock Exchange; the mothballing of certain units; the impact of certain hedges on future earnings, results and cash flows; estimates of fuel supply and demand conditions and the costs of procuring fuel; expectations for demand for electricity, including for clean energy, in both the short term and long term, and the resulting impact on electricity prices; the impact of load growth, increased capacity, and natural gas and other fuel costs on power prices; expectations in respect of generation availability, capacity and production; expectations regarding the role different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, including the change to a capacity market in Alberta and the expected impact on us and the timing of the implementation of such regimes and regulations, as well as the cost of complying with resulting regulations and laws; our marketing and trading strategy and the risks involved in these strategies; estimates of future tax rates, future tax expense and the adequacy of tax provisions; changes in accounting estimates and accounting policies; anticipated growth rates and competition in our markets; our expectations and obligations and anticipated liabilities relating to the outcome of existing or potential legal and contractual claims, regulatory investigations and disputes; expectations regarding the renewal of collective bargaining agreements; expectations for the ability to access capital markets at reasonable terms; the estimated impact of changes in interest rates and the value of the Canadian dollar relative to the US dollar and other currencies in locations where we do business; the monitoring of our exposure to liquidity risk; expectations in respect to the global economic environment and growing scrutiny by investors relating to sustainability performance; and our credit practices.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations, including any tax and regulatory changes in the markets in which we operate; no material adverse impacts to the investment and credit markets; assumptions related to 2019 guidance include: Alberta spot power price equal to \$50 to \$60 per megawatt hours ("MWh"); Alberta contracted power price equal to \$50 to \$55 per MWh; Mid-C spot power prices equal to US\$20 to US\$25 per MWh; Mid-C contracted power price of US\$47 to US\$53 per MWh; sustaining capital between \$160 million and \$190 million; productivity capital of \$10 million to \$15 million; Sundance coal capacity factor of 30% and hydro and wind resource being approximately in line with long-term averages; our proportionate ownership of TransAlta Renewables not changing materially; no decline in the dividends to be received from TransAlta Renewables; the expected life extension of the coal fleet and anticipated financial results generated on conversion; assumptions regarding the ability of the converted units to successfully compete in the Alberta capacity market; and assumptions regarding our current strategy and priorities, including as it pertains to our current priorities relating to the coal-to-gas conversions, growing TransAlta Renewables and being able to realize the full economic benefit from the capacity, energy and ancillary services from our Alberta hydro assets once the applicable power purchase arrangement has expired.

Forward-looking statements are subject to a number of significant risks, uncertainties and assumptions that could cause actual plans, performance, results or outcomes to differ materially from current expectations. Factors that may adversely impact what is expressed or implied by forward-looking statements contained in this MD&A include, but are not limited to, risks relating to: fluctuations in market prices; changes in demand for electricity and capacity and our ability to contract our generation for prices that will provide expected returns and replace contracts as they expire; the legislative, regulatory and political environments in the jurisdictions in which we operate; environmental requirements and changes in, or liabilities under, these requirements; changes in general economic or market conditions including interest rates; operational risks involving our facilities, including unplanned outages at such facilities; disruptions in the transmission and distribution of electricity; the effects of weather and other climate-change related risks; unexpected increases in cost structure and disruptions in the source of fuels, water or wind required to operate our facilities; failure to meet financial expectations; natural and man-made disasters, including those resulting in dam or dyke failures; the threat of domestic terrorism and cyberattacks; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner; commodity risk management and energy trading risks; industry risk and competition; the need to engage or rely on certain stakeholder groups and third parties; fluctuations in the value of foreign currencies and foreign political risks; the need for and availability of additional financing; structural subordination of securities; counterparty credit risk; changes in credit and market conditions; changes to our relationship with, or ownership of, TransAlta Renewables; risks associated with development projects and acquisitions, including capital costs, permitting, labour and engineering risks, and delays in the construction or commissioning of projects or delays in the closing of acquisitions; increased costs or delays in the construction or commissioning of pipelines to converted units; changes in expectations in the payment of future dividends, including from TransAlta Renewables Inc.; inadequacy or unavailability of insurance coverage; downgrades in credit ratings; our provision for income taxes; legal, regulatory and contractual disputes and proceedings involving the Corporation, including as it pertains to establishing commercial operations at the South Hedland Power Station; reliance on key personnel; and labour relations matters. The foregoing risk factors, among others, are described in further detail in the Governance and Risk Management section of this MD&A and the Risk Factors section in our Annual Information Form for the year ended Dec. 31, 2018.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements and are cautioned not to place undue reliance on them, which reflect the Corporation's expectations only as of the date hereof. 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 statements might occur to a different extent or at a different time than we have described, or might not occur at all. 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 consolidated 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 consolidated financial statements but is not presented elsewhere in the consolidated 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, 2018, 2017 and 2016. 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, are not standard measures 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, FCF, total consolidated net debt, adjusted net debt and segmented cash flow generated by the business, all as defined below, are non-IFRS measures that are presented in this MD&A. See the Discussion of Consolidated Financial Results, Segmented Comparable Results, Key Financial Ratios and TransAlta's Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

## Business Model

### Our Business

We are one of Canada's largest publicly traded power generators with over 108 years of operating experience. We own, operate and manage a highly contracted and geographically diversified portfolio of assets representing 8,273 MW<sup>(1)</sup> of capacity and use a broad range of generation fuels comprised of coal, natural gas, water, solar and wind. Our energy marketing operations maximize margins by securing and optimizing high-value products and markets for ourselves and our customers in dynamic market conditions.

### Vision and Values

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

### Strategy for Value Creation

Our goals are to deliver 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, balancing capital allocation and maintaining financial strength to allow for financial flexibility. Our comparable cash flow growth is driven by optimizing and diversifying our existing assets and further expanding our overall portfolio and operations in Canada, the US and Australia. We are focusing on these geographic areas as our expertise, scale and diversified fuel mix allow us to create expansion opportunities in our core markets.

### 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. This MD&A integrates our financial and sustainability reporting.

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

## Highlights

### Consolidated Financial Highlights

Year ended Dec. 31	2018	2017	2016
Revenues	2,249	2,307	2,397
Net earnings (loss) attributable to common shareholders	(248)	(190)	117
Cash flow from operating activities	820	626	744
Comparable EBITDA <sup>(1)</sup>	1,123	1,062	1,144
FFO <sup>(1)</sup>	927	804	734
FCF <sup>(1)</sup>	524	328	257
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.86)	(0.66)	0.41
FFO per share <sup>(1)</sup>	3.23	2.79	2.55
FCF per share <sup>(1)</sup>	1.83	1.14	0.89
Dividends declared per common share	0.20	0.12	0.20
Dividends declared per preferred share <sup>(2)</sup>	1.29	0.77	1.36
<b>As at Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Total assets	9,428	10,304	10,996
Total consolidated net debt <sup>(1)(3)</sup>	3,141	3,363	3,893
Total long-term liabilities	4,421	4,311	5,116

(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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

(2) Weighted average of the Series A, B, C, E, and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.

(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 total consolidated net debt.

FCF, one of the Corporation's key financial metrics, totalled \$524 million, up \$196 million compared to last year. After adjusting for the one-time receipt for the termination of the Sundance B and C power purchase arrangements ("PPAs") in 2018 and the Ontario Electricity Financial Corporation ("OEFCC") payment in 2017 (net of our partners share), FCF was \$367 million or \$56 million higher than 2017. FFO was \$927 million for 2018, compared to \$804 million for 2017, an increase of \$123 million.

- All generation segments had cash flows equal to or better than the same period last year.
- In Alberta, Canadian Coal, Hydro and our wind assets benefited from higher power prices. Average prices during the year in Alberta increased to \$50 per MWh from \$22 per MWh in 2017, mainly reflecting the impact of higher carbon pricing costs paid by certain generators and stronger market conditions.
- Canadian Coal cash flows were significantly higher in 2018 compared to 2017 as the cash flows in the first quarter included the one-time receipt for the termination of the Sundance B and C PPAs, which reflects the receipt of the capacity payments that would have been received over the 2018 to 2020 period had these PPAs not been terminated.
- Sustaining capital was lower in 2018 relative to 2017, primarily because of lower capital requirements in Canadian Coal as a result of the retirement of Sundance Units 1 and 2 and the mothballing of Sundance Units 3 and 5, and lower capital requirements in Canadian Gas and US Coal, mainly due to the timing of outages.

Revenues in 2018 were \$2,249 million, down \$58 million compared to 2017, mainly as a result of lower production within the Canadian Coal segment due to the retirement of Sundance Units 1 and 2 and the mothballing of Sundance Units 3 and 5 resulting from the termination of the Sundance B and C PPAs. This was partially offset by increased prices in the Alberta market.

Comparable EBITDA for the year ended Dec. 31, 2018, was \$1,123 million, up \$61 million compared to 2017, mainly due to the one-time receipt of \$157 million for the termination of the Sundance B and C PPAs, partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs. Excluding unrealized mark-to-market losses, comparable EBITDA was \$1,145 million. Beginning in the first quarter of 2019, unrealized mark-to-market gains or losses will be excluded from comparable EBITDA to be more comparable with other companies in the industry.

Net loss attributable to common shareholders in 2018 was \$248 million (\$0.86 net loss per share) compared to a net loss

of \$190 million (\$0.66 net earnings per share) in 2017. Earnings in 2018 were negatively impacted by higher mine depreciation and carbon compliance costs included in fuel and purchased power, higher impairments, lower finance lease income due to the sale of the Solomon facility, and higher preferred share dividends due to the timing of declarations, partially offset by the one-time receipt of \$157 million for the termination of the Sundance B and C PPAs and lower income tax expense. Net loss attributable to common shareholders in 2017 was 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.

### Significant Events

During 2018, our strategic focus continued to be on reducing our corporate debt, improving our operating performance and transitioning to clean power generation. The Corporation made the following progress in executing upon its strategy throughout the period:

- On Dec. 17, 2018, we exercised our option to acquire a 50 per cent ownership in the gas pipeline ("Pioneer Pipeline") connecting Tidewater Midstream and Infrastructure Ltd.'s ("Tidewater") Brazeau River Complex to TransAlta's generating units at Sundance and Keephills. Our investment is subject to regulatory approval.
- On Dec. 17, 2018, the Corporation announced that we will invest \$270 million in our 207 MW Windrise wind project, which was selected by the Alberta Electric System Operator ("AESO") as one of the two successful projects in the Renewable Electricity Program Round 3.
- On Nov. 13, 2018, we appointed Christophe Dehout as our Chief Financial Officer, replacing Brett Gellner (our then interim Chief Financial Officer), who continues to serve as our Chief Strategy and Investment Officer. Mr. Dehout brings broad experience in power generation and extensive knowledge of capital markets, mergers and acquisitions, corporate finance and corporate transformations.
- On Oct. 19, 2018, TransAlta Renewables announced that the 17.25 MW expansion of the wind facility at Kent Hills, New Brunswick, is fully operational, bringing total generating capacity at the site to 167 MW.
- On Aug. 2, 2018, the Corporation redeemed all of our then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for approximately \$425 million, including the principal amount of \$400 million, a prepayment premium and accrued and unpaid interest.
- On July 20, 2018, the Corporation monetized the payments under the Off-Coal Agreement ("OCA") with the Government of Alberta and closed an approximate \$345 million bond offering bearing interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.
- On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters. The shares were issued at a price of \$12.65 per share for gross proceeds of approximately \$150 million.
- On May 31, 2018, TransAlta Renewables acquired an economic interest in the 50 MW Lakeswind Wind Farm and 21 MW of solar projects located in the US ("Mass Solar") from TransAlta and acquired ownership of the 20 MW Kent Breeze Wind Farm located in Ontario. The total purchase price for the three assets was approximately \$166 million, including the assumption of \$62 million of tax equity obligations and project debt. On June 28, 2018, TransAlta Renewables subscribed for an additional \$33 million (US\$25 million) of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar in order to fund the repayment of Mass Solar's project debt.
- On March 15, 2018, the Corporation redeemed the then outstanding 6.650 per cent US \$500 million senior notes due May 15, 2018. The redemption price for the notes was approximately \$617 million (US\$516 million). Repayment of the US senior notes was funded by cash on hand and our credit facility.
- On Feb. 20, 2018, TransAlta Renewables entered into an arrangement to acquire two construction-ready wind 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 with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"). On April 20, 2018, TransAlta Renewables acquired an economic interest in the Big Level project. The Corporation expects the Antrim acquisition to close in early 2019.
- During the year, the Corporation purchased and cancelled 3,264,500 common shares at an average price of \$7.02 per common share through our normal course issuer bid ("NCIB") program, for a total cost of \$23 million.
- On March 31, 2018, the Corporation received approximately \$157 million in compensation for the termination of the Sundance B and C PPAs from the Balancing Pool.
- On Jan. 1, 2018, the Corporation permanently shutdown Sundance Unit 1 and mothballed Sundance Unit 2. On April 1, 2018, we mothballed Sundance Unit 3 and Sundance Unit 5. On July 31, 2018, we decided to permanently shut down Sundance Unit 2.

See the Significant and Subsequent Events section of this MD&A for further details.

## Discussion of Consolidated Financial Results

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, including the comparable figures below, 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 of the performance of our business:

- Certain assets we own in Canada (and in 2016 and 2017 in 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;
- 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;
- 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 received 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 recorded the payments we received as revenues as a proxy for operating income, and continued to depreciate the facility until Dec. 31, 2018; and
- On the commissioning of the South Hedland Power Station in July 2017, 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 a 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	2018	2017	2016
Net earnings (loss) attributable to common shareholders	(248)	(190)	117
Net earnings attributable to non-controlling interests	108	42	107
Preferred share dividends	50	30	52
<b>Net earnings (loss)</b>	<b>(90)</b>	<b>(118)</b>	<b>276</b>
<i>Adjustments to reconcile net income to comparable EBITDA</i>			
Income tax expense (recovery)	(6)	64	38
Gain on sale of assets and other	(1)	(2)	(4)
Foreign exchange (gain) loss	15	1	5
Net interest expense	250	247	229
Depreciation and amortization	574	635	601
<i>Comparable reclassifications</i>			
Decrease in finance lease receivables	59	59	57
Mine depreciation included in fuel cost	140	75	65
Australian interest income	4	2	–
<i>Adjustments to earnings to arrive at comparable EBITDA</i>			
Impacts to revenue associated with certain de-designated and economic hedges	–	2	26
Impacts associated with Mississauga recontracting <sup>(1)</sup>	105	77	(177)
Asset impairment charge <sup>(2)</sup>	73	20	28
<b>Comparable EBITDA</b>	<b>1,123</b>	<b>1,062</b>	<b>1,144</b>

(1) Impacts associated with Mississauga recontracting for the year ended Dec. 31, 2018, are as follows: revenue (\$108 million), and fuel and purchased power and de-designated hedges (\$3 million). 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 a 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).

(2) Asset impairment charges for 2018 include a \$38 million charge related to the retirement of Sundance Unit 2, Lakeswind and Kent Breeze impairment of \$12 million and a write-off of project development costs of \$23 million (2017 - \$20 million retirement of Sundance Unit 1, 2016 - \$28 million for the Wintering Hills impairment).

Comparable EBITDA increased by \$61 million for the year ended Dec. 31, 2018, compared to 2017. This was mainly due to:

- Our Canadian Coal and Hydro segments were up year over year, and together accounted for an increase of \$110 million of comparable EBITDA.
  - At Canadian Coal, the one-time receipt of \$157 million for the termination of the Sundance B and C PPAs was partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs.
  - Our Hydro operations benefited from higher market prices for Ancillary Services.
- Our US Coal, Canadian Gas and Australian Gas segments were down compared to 2017 for a combined decrease of \$44 million.
  - US Coal was down primarily due to non-cash mark-to-market losses.
  - Our Canadian Gas segment was lower mainly because 2017 comparable EBITDA benefited from the settlement of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor generating facilities, totalling \$34 million, which was mostly offset by the positive impact of the Mississauga recontracting and cost reduction initiatives.
  - Our Australian Gas segment was lower mainly due to lower finance income as a result of Fortescue Metals Group Ltd.'s ("FMG") repurchase of the Solomon Power Station partially offset by a full year of operations for the South Hedland Power Station.
- Our Wind and Solar segment benefited from higher merchant prices and insurance proceeds from a tower fire at Wyoming Wind Farm, which were offset by the unfavourable impact of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract, resulting in flat comparable EBITDA.
- Energy Marketing was down \$2 million in 2018 compared to 2017, but overall, largely consistent year over year.
- Corporate costs remained consistent with 2017 results.

Our overall results in 2018 included costs of approximately \$16 million (2017 - \$29 million) in operations, maintenance and administration ("OM&A") and \$21 million (2017 - \$25 million) in productivity capital relating to Project Greenlight, our transformation initiative. We estimate that the Project Greenlight initiatives generated net \$70 million in gross margin,



OM&A expenses and capital savings. See the Power Generating Portfolio Capital and Strategic Growth and Corporate Transformation sections of this MD&A for further details regarding Project Greenlight.

### 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:

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Cash flow from operating activities	820	626	744
Change in non-cash operating working capital balances	44	114	(73)
<b>Cash flow from operations before changes in working capital</b>	<b>864</b>	<b>740</b>	<b>671</b>
Adjustments			
Decrease in finance lease receivable	59	59	57
Other	4	5	6
<b>FFO</b>	<b>927</b>	<b>804</b>	<b>734</b>
Deduct:			
Sustaining capital	(168)	(235)	(272)
Productivity capital	(21)	(24)	(8)
Dividends paid on preferred shares	(40)	(40)	(42)
Distributions paid to subsidiaries' non-controlling interests	(169)	(172)	(151)
Other	(5)	(5)	(4)
<b>FCF</b>	<b>524</b>	<b>328</b>	<b>257</b>
Weighted average number of common shares outstanding in the year	287	288	288
<b>FFO per share</b>	<b>3.23</b>	<b>2.79</b>	<b>2.55</b>
<b>FCF per share</b>	<b>1.83</b>	<b>1.14</b>	<b>0.89</b>

The increase in FCF was driven by year-over-year stronger cash flow from operating activities of \$194 million partially due to the payment for the termination of the Sundance B and C PPAs and lower sustaining and productivity capital expenditures. Higher FCF in 2017 compared to 2016 was also driven by strong cash flow from operations before changes in working capital and reduced sustaining and productivity capital expenditures. FCF in 2016 was lower due to payments made to the Market Surveillance Administrator of \$25 million.

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

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Comparable EBITDA	<b>1,123</b>	1,062	1,144
Provisions	<b>7</b>	(7)	(114)
Unrealized (gains) losses from risk management activities	<b>22</b>	(28)	4
Interest expense	<b>(187)</b>	(218)	(229)
Current income tax expense	<b>(28)</b>	(23)	(23)
Realized foreign exchange gain (loss)	<b>5</b>	15	(5)
Decommissioning and restoration costs settled	<b>(31)</b>	(19)	(23)
Other cash and non-cash items	<b>16</b>	22	(20)
<b>FFO</b>	<b>927</b>	804	734
Deduct:			
Sustaining capital	<b>(168)</b>	(235)	(272)
Productivity capital	<b>(21)</b>	(24)	(8)
Dividends paid on preferred shares	<b>(40)</b>	(40)	(42)
Distributions paid to subsidiaries' non-controlling interests	<b>(169)</b>	(172)	(151)
Other	<b>(5)</b>	(5)	(4)
<b>FCF</b>	<b>524</b>	328	257

### Segmented Comparable Results

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, provisions, and non-cash mark-to-market gains or losses. This is the cash flow available to: pay our interest and cash taxes, make distributions to our non-controlling partners and pay dividends to our preferred shareholders, grow the business, pay down debt and return capital to our shareholders.

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
<b>Segmented cash flow<sup>(1)</sup></b>			
Canadian Coal <sup>(2)</sup>	<b>279</b>	175	198
US Coal	<b>63</b>	33	21
Canadian Gas <sup>(3)</sup>	<b>228</b>	221	235
Australian Gas	<b>136</b>	127	99
Wind and Solar	<b>211</b>	201	180
Hydro	<b>96</b>	61	53
<b>Generation segmented cash flow</b>	<b>1,013</b>	818	786
Energy Marketing	<b>33</b>	39	25
Corporate	<b>(107)</b>	(108)	(95)
<b>Total segmented cash flow</b>	<b>939</b>	749	716

(1) Segmented cash flow is a non-IFRS measure.

(2) 2018 includes \$157 million received from the Balancing Pool for the early termination of the Sundance B and C PPAs in the first quarter of 2018.

(3) 2017 includes \$34 million from the OEFC relating to the 2017 indexation dispute.

Cash flow generated by the business totalled \$939 million in 2018, up \$190 million over 2017, mainly due to the one-time receipt of \$157 million for the termination of the Sundance B and C PPAs, lower sustaining capital expenditures and higher Ancillary Services revenue from our hydro facilities. Cash flow in 2017 was \$33 million higher than 2016 due to disciplined cost control and sustaining capital expenditure allocation.

## Canadian Coal

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Availability (%)	91.6	82.0	85.3
Contract production (GWh)	8,936	18,683	19,823
Merchant production (GWh)	5,304	3,786	3,787
Total production (GWh)	14,240	22,469	23,610
Gross installed capacity (MW) <sup>(1)</sup>	3,231	3,791	3,791
Revenues	912	999	1,048
Fuel and purchased power	526	510	386
<b>Comparable gross margin</b>	<b>386</b>	<b>489</b>	<b>662</b>
Operations, maintenance and administration	171	192	178
Taxes, other than income taxes	13	13	13
Net other operating expense (income) <sup>(2)</sup>	(198)	(40)	(2)
<b>Comparable EBITDA</b>	<b>400</b>	<b>324</b>	<b>473</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital	17	22	33
Mine capital	42	28	23
Finance leases	14	14	13
Planned major maintenance	15	54	100
<b>Total sustaining capital expenditures</b>	<b>88</b>	<b>118</b>	<b>169</b>
Productivity capital	12	12	1
<b>Total sustaining and productivity capital</b>	<b>100</b>	<b>130</b>	<b>170</b>
Provisions	(10)	5	85
Unrealized gains (losses) on risk management activities	11	3	7
Decommissioning and restoration costs settled	19	11	13
Other	1	—	—
<b>Canadian Coal cash flow</b>	<b>279</b>	<b>175</b>	<b>198</b>

(1) On Jan. 1, 2018, 560 MW Sundance Units 1 and 2 were shut down and mothballed, respectively. On April 1, 2018, 774 MW Sundance Units 3 and 5 were mothballed. On July 31, 2018 Sundance Unit 2 was shut down permanently.

(2) In 2018, this includes the \$157 million payment for the termination of the Sundance B and C PPAs. In both 2018 and 2017, this includes the \$40 million OCA payment.

**2018**

Availability for the year improved compared to 2017, mainly due to lower planned outages and unplanned outages and derates in 2018.

Production for the year ended Dec. 31, 2018, decreased 8,229 gigawatt hours ("GWh") compared to 2017, primarily due to the retirement and mothballing of certain Sundance units and less dispatching, partially offset by lower planned and unplanned outages.

Revenue for the year ended Dec. 31, 2018, decreased by \$87 million compared to 2017, mainly due to lower production offset by higher prices. Revenue per MWh of production rose to approximately \$64 per MWh in 2018 from \$44 per MWh in 2017, which more than offset the increase in carbon compliance costs and resulted in higher gross margin per MWh in 2018.

Fuel, carbon compliance costs and purchased power costs per MWh were higher in 2018 compared to 2017. Coal costs on a dollar per MWh were higher due to fixed costs and lower tonnage. Pit development work commenced in 2018 at the Highvale mine and is expected to provide the lowest cost fuel for the remaining life of the facilities. Carbon compliance costs were higher in 2018, reflecting the regulated increase in the carbon price and due to the fact that carbon compliance costs are no longer recoverable on the Sundance units as the PPAs have been terminated. Both the fuel and carbon pricing cost increases were as expected.

During the year we commenced co-firing with natural gas. Natural gas combustion produces fewer greenhouse gas ("GHG") emissions than coal combustion, which lowers our GHG compliance costs. The combined impact of relatively low Alberta

gas prices and lower GHG compliance costs made this economically viable on the merchant plants for a substantial part of the year.

OM&A costs were lower in 2018 compared to 2017. There are certain fixed and common costs that are required to maintain the remaining operational Sundance units and some one-time OM&A costs were incurred in association with the mothballing and retirement of Sundance Units 1 and 2. We continue to optimize the operations of the facility in response to the merchant market.

Comparable EBITDA for the year ended Dec. 31, 2018, increased \$76 million compared to 2017, as a result of the one-time receipt of \$157 million for the termination of the Sundance B and C PPAs, partially offset by higher carbon compliance costs and reduced revenue relating to the termination of the Sundance B and C PPAs.

For the year ended Dec. 31, 2018, sustaining capital expenditures decreased by \$30 million compared to 2017, mainly due to lower planned outages and mothballing of units, partially offset by increased mine pit development work. Establishing a new pit provides the lowest cost fuel for the remaining life of the facilities. In 2017, four planned outages were performed throughout the year, while during 2018 there was only one planned major outage at one of our non-operated plants. Overall, for 2018, there are four fewer units in the fleet to maintain, which significantly reduced our sustaining capital costs.

## 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 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 were 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.

The 2017 results also included \$40 million related to OCA payments included in net other operating income. We received our OCA payment in the third quarter.

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.

## US Coal

Year ended Dec. 31	2018	2017	2016
Availability (%)	60.2	66.3	88.1
Adjusted availability (%) <sup>(1)</sup>	84.6	86.2	88.9
Contract sales volume (GWh)	3,329	3,609	3,535
Merchant sales volume (GWh)	5,704	5,488	4,896
Purchased power (GWh)	(3,665)	(3,625)	(3,854)
Total production (GWh)	5,368	5,472	4,577
Gross installed capacity (MW)	1,340	1,340	1,340
Revenues	442	437	380
Fuel and purchased power	314	293	281
<b>Comparable gross margin</b>	<b>128</b>	<b>144</b>	<b>99</b>
Operations, maintenance and administration	61	51	54
Taxes, other than income taxes	5	4	4
<b>Comparable EBITDA</b>	<b>62</b>	<b>89</b>	<b>41</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital	2	3	3
Finance leases	4	3	3
Planned major maintenance	11	29	11
<b>Total sustaining capital expenditures</b>	<b>17</b>	<b>35</b>	<b>17</b>
Productivity capital	—	3	—
<b>Total sustaining and productivity capital</b>	<b>17</b>	<b>38</b>	<b>17</b>
Provisions	—	—	7
Unrealized gains (losses) on risk management activities	(29)	10	(13)
Decommissioning and restoration costs settled	11	8	9
<b>US Coal cash flow</b>	<b>63</b>	<b>33</b>	<b>21</b>

(1) Adjusted for dispatch optimization.

## 2018

Availability for the year was down compared to 2017 due to the timing of dispatch optimization and unplanned outages and derates in the last half of 2018, slightly offset by forced outages at Centralia Unit 1 in January 2017. In 2017 and 2018, both Centralia Units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In both years, we performed major maintenance during that time.

Production was down 104 GWh in 2018 compared to 2017, due mainly to dispatch optimization and increased unplanned outages in the last half of the year.

OM&A costs were \$10 million higher in 2018 compared to 2017, due to employee gainshare, annual incentive compensation and retention bonuses, as well as increased disbursements paid to the community fund.

Comparable EBITDA decreased by \$27 million compared to 2017 primarily due to unfavourable changes on unrealized mark-to-market positions recorded within fuel and purchased power offset by reduced coal costs and favourable market prices.

Sustaining and productivity capital expenditures for 2018 were \$21 million lower than 2017, due to lower planned outages.

US Coal's 2018 cash flow improved by \$30 million compared to the prior year, mainly due to stronger operating results excluding unrealized mark-to-market impacts and lower sustaining and productivity capital spend.

## 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 low prices in the Pacific Northwest market. We performed major maintenance on both units during that time. The lower availability was not material to 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 dispatch optimization caused by higher prices in the fourth quarter of 2017. 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 the year ended Dec. 31, 2017, increased by \$21 million compared to 2016 due to planned outages executed during the second quarter of 2017. Productivity capital was invested in the installation of inspection equipment to optimize heat rates on coal and improve air distribution systems.

## Canadian Gas

Year ended Dec. 31	2018	2017	2016
Availability (%)	93.3	91.6	95.7
Contract production (GWh)	1,620	1,504	2,784
Merchant production (GWh)	93	244	288
Total production (GWh)	1,713	1,748	3,072
Gross installed capacity (MW) <sup>(1)</sup>	945	952	1,057
Revenues	407	430	470
Fuel and purchased power	99	113	171
<b>Comparable gross margin</b>	<b>308</b>	<b>317</b>	<b>299</b>
Operations, maintenance and administration	48	53	54
Taxes, other than income taxes	1	1	1
<b>Comparable EBITDA</b>	<b>259</b>	<b>263</b>	<b>244</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital	4	8	7
Planned major maintenance	16	22	5
<b>Total sustaining capital expenditures</b>	<b>20</b>	<b>30</b>	<b>12</b>
Productivity capital	2	2	—
<b>Total sustaining and productivity capital</b>	<b>22</b>	<b>32</b>	<b>12</b>
Provisions	—	3	(2)
Unrealized gains (losses) on risk management activities	9	7	(2)
Decommissioning and restoration costs settled	—	—	1
<b>Canadian Gas cash flow</b>	<b>228</b>	<b>221</b>	<b>235</b>

(1) 2018 and 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.

## 2018

Availability for the year ended Dec. 31, 2018, increased 1.7 per cent compared to 2017, mainly due to the 2017 base cycling conversion project at Windsor and lower planned and unplanned outages at Sarnia and Windsor in 2018.

Production for the year decreased 35 GWh compared to 2017, as lower market demand at Sarnia was partially offset by higher production at the Fort Saskatchewan, Ottawa and Windsor facilities.

Comparable EBITDA for 2018 decreased by \$4 million compared to 2017, mainly due to the retroactive contract indexation dispute settlement with the OEFC in 2017 (\$34 million) offset by the positive impact from the Mississauga recontracting, higher realized pricing at Sarnia and cost reduction initiatives. The Mississauga, Ottawa, Windsor, and our 60 per cent share of Fort Saskatchewan, generating facilities are owned through our 50.01 per cent interest in TransAlta Cogeneration L.P. ("TA Cogen"). The Mississauga recontracting ended in December 2018 and was not renewed.

Sustaining capital totalled \$20 million in 2018, a decrease of \$10 million mainly due to higher capital spend in 2017, when we completed the scheduled maintenance at Sarnia and the base cycling conversion project at Windsor to increase its flexibility to respond to market prices.

Cash flow at Canadian Gas improved by \$7 million for the year ended Dec. 31, 2018, compared to the prior year mainly due to lower sustaining capital spend in 2018, partially offset by lower EBITDA. In 2017, one-time sustaining capital expenditures were incurred for the Windsor base cycling conversion project.

## 2017

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.

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.

In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. in Mississauga effective Dec. 31, 2021. TransAlta is required to remove the Mississauga plant and restore the site within the three-year time frame.

## Australian Gas

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Availability (%)	94.0	93.4	93.1
Contract production (GWh)	1,814	1,803	1,529
Gross installed capacity (MW) <sup>(1)</sup>	450	450	425
Revenues	165	180	174
Fuel and purchased power	4	12	20
<b>Comparable gross margin</b>	<b>161</b>	<b>168</b>	<b>154</b>
Operations, maintenance and administration	37	31	25
Taxes, other than income taxes	—	—	1
<b>Comparable EBITDA</b>	<b>124</b>	<b>137</b>	<b>128</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital	2	9	3
Planned major maintenance	—	1	11
<b>Total sustaining and productivity capital</b>	<b>2</b>	<b>10</b>	<b>14</b>
Other	(14)	—	15
<b>Australian Gas cash flow</b>	<b>136</b>	<b>127</b>	<b>99</b>

(1) The 2016 figures include production capacity for the Solomon Power Station, which was accounted for as a finance lease. In 2017, FMG repurchased the Solomon Power Station and therefore was removed from 2017 capacity, which was offset by adding capacity for the South Hedland Power Station, which achieved commercial operations on July 28, 2017.

**2018**

Availability for the year ended Dec. 31, 2018, increased compared to 2017, mainly due to a full year of operation from the South Hedland Power Station, which was offset by FMG's repurchase of the Solomon Power Station.

Production for 2018 was comparable to 2017, due to the addition of the South Hedland Power Station, which was offset by FMG's repurchase of the Solomon Power Station. Due to the nature of our contracts, changes in production do not have a significant financial impact as our contracts are structured as capacity payments with a pass-through of fuel costs.

Comparable EBITDA for the year decreased by \$13 million compared to 2017 mainly due to FMG's repurchase of Solomon Power Station, higher OM&A costs due to the addition of the South Hedland Power Station and ongoing legal costs associated with our dispute with FMG, which were partially offset by higher EBITDA from the South Hedland Power Station.

Sustaining and productivity capital for 2018 decreased by \$8 million compared to 2017, due to major maintenance incurred at our Southern Cross facility in August 2017 that was not required in 2018.

Cash flow at Australian Gas increased by \$9 million in 2018 mainly due to lower sustaining capital requirements and an increase in cash flow from the collection of a long-term receivable, largely offset by lower EBITDA.

**2017**

Production for 2017 increased by 274 GWh compared to 2016 due to the commissioning of our South Hedland Power Station in July 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.



## Wind and Solar

Year ended Dec. 31	2018	2017	2016
Availability (%)	95.4	95.8	94.9
Contract production (GWh)	2,363	2,362	2,301
Merchant production (GWh)	1,005	1,098	1,212
Total production (GWh)	3,368	3,460	3,513
Gross installed capacity (MW) <sup>(1)</sup>	1,382	1,363	1,408
Revenues	282	287	272
Fuel and purchased power	17	17	18
<b>Comparable gross margin</b>	<b>265</b>	<b>270</b>	<b>254</b>
Operations, maintenance and administration	50	48	52
Taxes, other than income taxes	8	8	8
Net other operating income	(6)	—	(1)
<b>Comparable EBITDA</b>	<b>213</b>	<b>214</b>	<b>195</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital	5	1	2
Planned major maintenance	8	10	11
<b>Total sustaining capital expenditures</b>	<b>13</b>	<b>11</b>	<b>13</b>
Productivity capital	2	2	3
<b>Total sustaining and productivity capital</b>	<b>15</b>	<b>13</b>	<b>16</b>
Provisions	—	—	(1)
Unrealized gains (losses) on risk management activities	(20)	—	—
Decommissioning and restoration costs settled	1	—	—
Other (insurance proceeds)	6	—	—
<b>Wind and Solar cash flow</b>	<b>211</b>	<b>201</b>	<b>180</b>

(1) The 2017 figure excludes capacity for the Wintering Hills wind facility, which was sold on March 1, 2017.

**2018**

Availability for the year ended Dec. 31, 2018, was comparable to 2017, which was expected.

Production for 2018 decreased by 92 GWh compared to 2017, mainly due to lower wind resources across Alberta and the United States combined with the sale of the Wintering Hills merchant facility on March 1, 2017. This lower production was partially offset by higher wind resources in Eastern Canada.

Comparable EBITDA for 2018 was comparable with 2017, as higher merchant prices in Alberta and insurance proceeds from the tower fire at Wyoming Wind Farm were offset by the unfavourable impact of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract and the unfavourable impact of lower wind resources.

Wind and Solar's cash flow improved by \$10 million for the year ended Dec. 31, 2018, compared to the prior year, due mainly to the addback of the US non-cash mark-to-market losses relating to the fair value of the Big Level PPA contract.

**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 in 2016.

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.

## Hydro

Year ended Dec. 31	2018	2017	2016
<b>Production</b>			
Energy contracted			
Alberta hydro PPA assets (GWh) <sup>(1)</sup>	1,519	1,530	1,410
Other hydro energy (GWh) <sup>(1)</sup>	306	336	358
Energy merchant			
Other hydro energy (GWh)	81	82	88
<b>Total energy production (GWh)</b>	<b>1,906</b>	<b>1,948</b>	<b>1,856</b>
Ancillary service volumes (GWh) <sup>(2)</sup>	3,265	3,044	2,623
Gross installed capacity (MW)	926	926	926
<b>Revenues</b>			
Alberta hydro PPA assets energy	90	36	28
Alberta hydro PPA assets ancillary	104	36	30
Capacity payments received under Alberta hydro PPA <sup>(3)</sup>	56	54	55
Other revenue <sup>(4)</sup>	41	43	50
<b>Total gross revenues</b>	<b>291</b>	<b>169</b>	<b>163</b>
Net payment relating to Alberta hydro PPA	(135)	(48)	(37)
<b>Revenues</b>	<b>156</b>	<b>121</b>	<b>126</b>
Fuel and purchased power	6	6	8
<b>Comparable gross margin</b>	<b>150</b>	<b>115</b>	<b>118</b>
Operations, maintenance and administration	38	37	33
Taxes, other than income taxes	3	3	3
Net other operating income	—	—	—
<b>Comparable EBITDA</b>	<b>109</b>	<b>75</b>	<b>82</b>
<b>Deduct:</b>			
<b>Sustaining capital:</b>			
Routine capital, excluding hydro life extension	4	8	8
Hydro life extension	—	—	9
Planned major maintenance	8	5	10
<b>Total before flood-recovery capital</b>	<b>12</b>	<b>13</b>	<b>27</b>
Flood-recovery capital	—	—	2
<b>Total sustaining capital expenditures</b>	<b>12</b>	<b>13</b>	<b>29</b>
Productivity capital	1	1	—
<b>Total sustaining and productivity capital</b>	<b>13</b>	<b>14</b>	<b>29</b>
<b>Hydro cash flow</b>	<b>96</b>	<b>61</b>	<b>53</b>

(1) Alberta hydro PPA assets include 12 hydro facilities on the Bow and North Saskatchewan river systems included under the PPA legislation. Other hydro facilities include our hydro facilities in BC, Ontario and the hydro facilities in Alberta not included in the legislated PPAs.

(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.

(3) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta Queen's Printer.

(4) Other revenue includes revenues from our non-PPA hydro facilities, our transmission business and other contractual arrangements including the flood mitigation agreement with the Alberta government and black start services.

## 2018

Production for 2018 decreased by 42 GWh over 2017, primarily due to lower water resources.

Comparable EBITDA for 2018 increased \$34 million compared to 2017. Alberta Hydro benefited from stronger energy prices and a higher demand for Ancillary Services.

Hydro's cash flow improved by \$35 million for 2018, compared to 2017, due mainly to higher comparable EBITDA.

**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 OM&A costs and a \$3 million positive adjustment relating to a prior year metering issue at one of our facilities recorded in 2016.

Sustaining capital expenditures 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.

**Energy Marketing**

<b>Year ended Dec. 31</b>	<b>2018</b>	<b>2017</b>	<b>2016</b>
Revenues and comparable gross margin	67	69	76
Operations, maintenance and administration	24	24	24
<b>Comparable EBITDA</b>	<b>43</b>	<b>45</b>	<b>52</b>
<b>Deduct:</b>			
Provisions	3	(2)	24
Unrealized gains (losses) on risk management activities	7	8	3
<b>Energy Marketing cash flow</b>	<b>33</b>	<b>39</b>	<b>25</b>

**2018**

Comparable EBITDA for 2018 remained fairly consistent with 2017 results, which was expected.

Energy Marketing's cash flows for 2018 decreased by \$6 million compared to 2017, mainly due to the settlement of trading positions adversely affected by cold weather in the first quarter and the removal of non-cash mark-to-market gains driven by a number of long-term trades that are expected to settle in 2019.

**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.

**Corporate****2018**

Our Corporate overhead costs of \$87 million were consistent in 2018 compared to 2017 as we realized benefits from cost-efficiency initiatives that were offset by the addition of the Supply Chain Management team, which will provide future cost savings by leveraging our buying power. Corporate cash flow also includes \$20 million (2017 - \$22 million) in sustaining and productivity capital spend.

**2017**

Our Corporate overhead costs of \$85 million were \$14 million higher for the year ended Dec. 31, 2017, compared to 2016 mostly due to higher annual incentive compensation 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.

## Key Financial Ratios

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

### Funds from Operations before Interest to Adjusted Interest Coverage

As at Dec. 31	2018	2017	2016
FFO	927	804	734
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	(157)	—	—
Add: Interest on debt and finance leases, net of interest income and capitalized interest	174	205	203
<b>FFO before interest</b>	<b>944</b>	<b>1,009</b>	<b>937</b>
Interest on debt and finance leases, net of interest income	176	214	219
Add: 50 per cent of dividends paid on preferred shares	20	20	21
<b>Adjusted interest</b>	<b>196</b>	<b>234</b>	<b>240</b>
<b>FFO before interest to adjusted interest coverage (times)</b>	<b>4.8</b>	<b>4.3</b>	<b>3.9</b>

Our target for FFO before interest to adjusted interest coverage is four to five times. The ratio improved compared to 2017 due to lower interest on debt as we continued to execute our deleveraging plan.

### Adjusted FFO to Adjusted Net Debt

As at Dec. 31	2018	2017	2016
FFO	927	804	734
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	(157)	—	—
Less: 50 per cent of dividends paid on preferred shares	(20)	(20)	(21)
<b>Adjusted FFO</b>	<b>750</b>	<b>784</b>	<b>713</b>
Period-end long-term debt <sup>(1)</sup>	3,267	3,707	4,361
Less: Cash and cash equivalents	(89)	(314)	(305)
Less: Principal portion of TransAlta OCP restricted cash	(27)	—	—
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt <sup>(2)</sup>	(10)	(30)	(163)
<b>Adjusted net debt</b>	<b>3,612</b>	<b>3,834</b>	<b>4,364</b>
<b>Adjusted FFO to adjusted net debt (%)</b>	<b>20.8</b>	<b>20.4</b>	<b>16.3</b>

(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, 2018, Dec. 31, 2017, and Dec. 31, 2016.

Our adjusted FFO to adjusted net debt of 20.8 per cent remained consistent with 2017, as the significant reduction in our net debt was offset by a decline in adjusted FFO. We reached the low end of our target range of 20 to 25 per cent in 2017 and maintained that level in 2018.

**Adjusted Net Debt to Comparable EBITDA**

As at Dec. 31	2018	2017	2016
Period-end long-term debt <sup>(1)</sup>	3,267	3,707	4,361
Less: Cash and cash equivalents	(89)	(314)	(305)
Less: Principal portion of TransAlta OCP restricted cash	(27)	—	—
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt <sup>(2)</sup>	(10)	(30)	(163)
<b>Adjusted net debt</b>	<b>3,612</b>	<b>3,834</b>	<b>4,364</b>
Comparable EBITDA	1,123	1,062	1,144
Less: Early termination of the Sundance PPAs received during the first quarter of 2018	(157)	—	—
<b>Adjusted comparable EBITDA</b>	<b>966</b>	<b>1,062</b>	<b>1,144</b>
<b>Adjusted net debt to comparable EBITDA (times)</b>	<b>3.7</b>	<b>3.6</b>	<b>3.8</b>

(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, 2018, Dec. 31, 2017, and Dec. 31, 2016.

Our adjusted net debt to comparable EBITDA ratio increased compared to 2017, mainly due to the decrease in adjusted comparable EBITDA during the year, after adjusting for the payment for the early termination of the Sundance B and C PPAs. Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times.

**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		2018	2017	2016
Comparable EBITDA	Target <sup>(1)</sup>	1,000-1,050	1,025-1,100	990-1,100
	Actual	1,123	1,062	1,144
	Adjusted Actual <sup>(2)</sup>	988	1,000	1,068
FFO	Target <sup>(1)</sup>	750-800	765-820	755-835
	Actual	927	804	734
	Adjusted Actual <sup>(3)</sup>	770	770	734
FCF	Target <sup>(1)</sup>	300-350	270-310	250-300
	Actual	524	328	257
	Adjusted Actual <sup>(3)</sup>	367	311	257

(1) Represents our revised outlook. As a result of strong performance in the first quarter of 2018, we revised the following 2018 targets: comparable EBITDA from the previously announced target range of \$950 million to \$1,050 million to \$1,000 to \$1,050 million, FFO from the target range of \$725 million to \$800 million to \$750 million to \$800 million FCF target range from \$275 million to \$350 million to the target range of \$300 million to \$350 million. In the second quarter of 2017 we reduced the following 2017 targets: Comparable EBITDA from target range of \$1,025 million to \$1,135 million to \$1,025 to \$1,100 million, FFO from the target range of \$765 million to \$855 million to \$765 million to \$820 million FCF target range from \$300 million to \$365 million to the target range of \$270 million to \$310 million.

(2) Comparable EBITDA for all periods was adjusted to remove the impact of unrealized mark-to-market gains or losses. Additionally, 2018 was adjusted to remove the \$157 million for the termination of the Sundance B and C PPAs as this was not included in the target. 2017 was also adjusted to remove the \$34 million related to the OEFC indexation dispute. 2016 was adjusted for the \$80 million impact for non-cash adjustments related to the Keephills 1 provision.

(3) 2018 amounts were adjusted to remove the \$157 million for the termination of the Sundance B and C PPAs as this was not included in the targets. 2017 amounts were adjusted to remove the OEFC indexation dispute: FFO was reduced by \$34 million and FCF was reduced by \$17 million.

## Significant and Subsequent Events

### Transition to Clean Power in Alberta

#### *Alberta Renewable Energy Program Project - Windrise*

In the fourth quarter of 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the two successful projects in the third round of the Renewable Electricity Program. The Windrise facility, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately \$270 million and is targeted to reach commercial operation during the second quarter of 2021.

#### *Gas Supply for Coal-to-Gas Conversions*

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. Tidewater will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline will provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately \$90 million. Construction of the pipeline commenced in November 2018 and the Pioneer Pipeline is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals, which are expected to be finalized in the first half of 2019.

The decision to work with Tidewater advances the time frame for the construction of the Pioneer 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.

#### *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. During 2018, the Corporation mothballed and retired the following Sundance Units:

- retired Sundance Unit 1 on Jan. 1, 2018;
- retired Sundance Unit 2 on July 31, 2018;
- temporarily mothballed Sundance Unit 3 on April 1, 2018, for a period of up to two years; and
- temporarily mothballed Sundance Unit 5 on April 1, 2018, for a period of up to one year, which has recently been extended to two years.

TransAlta is no longer planning to temporarily mothball Sundance Unit 4 and will perform maintenance during the first half of 2019.

On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The regulations provide rules for new gas-fired electricity facilities, as well as specific provisions for coal-to-gas conversions. In addition to extending their operating lives, the benefits of converting units to gas generation include: significantly lowering carbon emissions and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility. TransAlta expects to convert its Sundance Units 3 to 6 and Keephills Units 1 to 3 in the 2020 to 2023 time frame.

#### *Sundance Units 1 and 2*

Canadian 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 was shut down two years early, the federal Minister of Environment and Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This provided the Corporation with the flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market. However, in July 2018, TransAlta retired Sundance Unit 2. This decision was driven largely by Sundance Unit 2's age, size and short useful life relative to other units, and the capital requirements needed to return the unit to service.

Sundance Units 1 and 2 collectively made up 560 MW of the 2,141 MW capacity of the Sundance power plant, which served 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 third quarter of 2018, the Corporation recognized an impairment charge of \$38 million (\$28 million after-tax) relating to the retirement of Sundance Unit 2. During the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of \$20 million (\$15 million after-tax) due to the Corporation's decision to early retire Sundance Unit 1.

### **Kent Hills 3 Wind Project**

During 2017, a subsidiary of TransAlta Renewables Inc., 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 expansion 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.

On Oct. 19, 2018, TransAlta Renewables announced that the expansion was fully operational, bringing the total generating capacity of the Kent Hills wind farm to 167 MW.

### **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 Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 2018, whereas the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the Antrim acquisition to close in early 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables and a \$25 million promissory note receivable and are estimated to be US\$240 million. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs using its existing liquidity and tax equity.

During the year ended Dec. 31, 2018, TransAlta Renewables funded approximately \$61 million (US\$48 million) of construction costs for Big Level. On Jan. 2, 2019, TransAlta Renewables funded an additional \$45 million (US\$33 million) of construction costs.

### **TransAlta Renewables Acquires Three Renewable Assets from the Corporation**

On May 31, 2018, TransAlta Renewables acquired from a subsidiary of the Corporation an economic interest in the 50 MW Lakeswind wind farm in Minnesota and 21 MW of solar projects located in Massachusetts ("Mass Solar") through the subscription of tracking preferred shares of a subsidiary of the Corporation. In addition, TransAlta Renewables acquired from a subsidiary of the Corporation ownership of the 20 MW Kent Breeze wind farm located in Ontario. The total purchase price for the three assets was approximately \$166 million, including the assumption of \$62 million of tax equity obligations and project debt, for net cash consideration of \$104 million. The Corporation continues to operate these assets on behalf of TransAlta Renewables.

On June 28, 2018, TransAlta Renewables subscribed for an additional \$33 million of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar, in order to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a \$12 million impairment charge, of which \$11 million was recorded against property, plant and equipment ("PP&E") and \$1 million against intangibles.

### **TransAlta Renewables Closes \$150 Million Offering of Common Shares**

On June 22, 2018, TransAlta Renewables closed a bought deal offering of 11,860,000 common shares through a syndicate of underwriters. The common shares were issued at a price of \$12.65 per common share for gross proceeds of approximately \$150 million (\$144 million of net proceeds).

The net proceeds were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility is to be used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described above.

The Corporation did not purchase any additional common shares under the offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables.

### **\$345 Million Financing**

On July 20, 2018, the Corporation monetized the payments under the OCA with the Government of Alberta by closing a \$345 million bond offering through its indirect wholly owned subsidiary, TransAlta OCPLP ("TransAlta OCP"). The offering was a private placement that was secured by, among other things, a first ranking charge over the OCA payments payable by the Government of Alberta. The amortizing bonds bear interest at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030. The bonds have a rating of BBB, with a stable trend, by DBRS. Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately \$40 million (approximately \$37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The net proceeds were used to partially repay the 6.40 per cent debentures, as described below.

### **Early Redemption of \$400 million of Debentures**

On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of \$400 million. The redemption price was approximately \$425 million in aggregate, including a prepayment premium and accrued and unpaid interest.

### **Normal Course Issuer Bid**

On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.86 per cent of issued and outstanding common shares as at March 2, 2018. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018, and ends on March 13, 2019, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation's election.

Under TSX rules, not more than 102,039 common shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 common shares for the six months ended February 28, 2018) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled 3,264,500 common shares at an average price of \$7.02 per common share, for a total cost of \$23 million. Further transactions under the NCIB, if any, will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

### **Early Redemption of Senior Notes**

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US \$500 million senior notes due May 15, 2018, for approximately \$617 million (US\$516 million). A \$5 million early redemption premium was recognized in net interest expense for the three months ended March 31, 2018.

### **Management and Board of Directors Changes**

Donald Tremblay, the former Chief Financial Officer ("CFO"), left the Corporation, effective May 9, 2018. Brett Gellner, Chief Strategy and Investment Officer, acted as Interim CFO, in addition to his current role, during the interim period.

During the fourth quarter of 2018, we appointed Christophe Dehout as our CFO. Mr. Dehout brings broad experience in power generation and extensive knowledge of capital markets, mergers and acquisitions, corporate finance and corporate transformations.



On January 25, 2019, we announced the retirement decisions of Timothy Faithfull and Ambassador Gordon Giffin. Earlier in 2018, Mr. Faithfull had indicated to the Board his intention to retire from the Board of Directors immediately following TransAlta's 2019 Annual Shareholders Meeting and, also in 2018, Ambassador Gordon Giffin announced his intention to retire as director and Board Chair in 2020. The Board is undertaking a process to identify a new Chair through the course of 2019.

**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 PPAs effective March 31, 2018.

The termination of the Sundance B and C 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 B and C PPAs and applicable legislation. The Balancing Pool paid the Corporation approximately \$157 million on March 29, 2018, as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional \$56 million. The dispute is currently proceeding through arbitration.

Please refer to Note 4 of the audited annual 2018 consolidated financial statements for significant events impacting prior year results.

## Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2017, to Dec. 31, 2018:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	(225)	Timing of receipts and payments.
Restricted cash (current & long-term)	36	Restricted cash related to the TransAlta OCP bonds (\$35 million)
Trade and other receivables	(177)	Timing of customer receipts, collection of Mississauga recontracting receivable (\$108 million), partially offset by the Antrim promissory note receivable (\$25 million)
Inventory	23	Increase in Canadian Coal (\$50 million) partially offset by a reduction in purchased emission credits (\$13 million) and a reduction in parts and materials inventory (\$5 million)
Finance lease receivables (long term)	(24)	Principal repayments
Property, plant, and equipment, net	(414)	Depreciation for the period (\$649 million), revisions to decommissioning and restoration costs (\$32 million) and asset impairments (\$49 million), partially offset by additions (\$294 million) and favourable changes in foreign exchange rates (\$39 million)
Intangible assets	9	Additions of (\$53 million) and net transfers from PP&E (\$6 million), partially offset by amortization (\$50 million)
Risk management assets (current and long term)	(95)	Contract settlements and unfavourable market price movements, partially offset by favourable changes in foreign exchange rates
Other	(9)	
<b>Total change in assets</b>	<b>(876)</b>	
Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(98)	Timing of payments and accruals
Income taxes payable	(54)	Primarily due to the payment of taxes on FMG's repurchase of the Solomon Power Station
Credit facilities, long term debt, and finance lease obligations (including current portion)	(440)	Repayment of long-term debt (\$1,179 million), partially offset by drawings on the credit facility (\$312 million), long-term debt issued (\$345 million) and unfavourable changes in foreign exchange (\$95 million)
Decommissioning and other provisions (current and long term)	(14)	Liabilities settled (\$41 million) and an increase in risk-adjusted discount rates (\$37 million), partially offset by accretion (\$24 million), new liabilities incurred (\$22 million), remaining payment for Big Level acquisition (\$8 million) and unfavourable changes in foreign exchange (\$10 million)
Contract liabilities	25	Increased due to IFRS 15 transition adjustment (\$17 million), consideration received (\$13 million) and interest accrued and expensed during the period (\$6 million), partially offset by transfers to revenue (\$10 million)
Defined benefit obligation and other long term liabilities	(10)	Decrease in the defined benefit obligation (\$8 million) and reduced employee incentive plan liability (\$7 million), partially offset by increased other long-term liabilities (\$5 million)
Deferred income tax liabilities	(48)	Decrease in taxable temporary differences
Equity attributable to shareholders	(329)	Net loss (\$198 million), net other comprehensive loss (\$12 million) common share dividends (\$57 million), preferred share dividends (\$50 million), shares purchased under NCIB (\$23 million), impact of changes in our accounting policies (\$14 million), partially offset by changes in non-controlling interests in TransAlta Renewables (\$24 million)
Non-controlling interests	78	Net earnings (\$108 million), changes in non-controlling interests in TransAlta Renewables from share issuance (\$133 million) and intercompany FVOCI investments (\$16 million), partially offset by distributions paid and payable (\$180 million)
Other	14	
<b>Total change in liabilities and equity</b>	<b>(876)</b>	

## Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2017, and Dec. 31, 2016, compared to the year ended Dec. 31, 2018:

Year ended Dec. 31	2018	2017	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents, beginning of year	314	305	9	
Provided by (used in):				
Operating activities	820	626	194	Higher cash flow from operations before working capital (\$124 million) and a favourable change in non-cash working capital (\$70 million)
Investing activities	(394)	87	(481)	Lower proceeds on sale of Wintering Hills wind facility and Solomon (\$476 million), unfavourable change in non-cash investing capital (\$153 million) and the acquisition of Big Level and Antrim (\$30 million), partially offset by lower additions to property, plant, and equipment (\$63 million), lower tax expense relating to investing activities (\$56 million), lower additions to intangibles (\$31 million), and the lower issuance of loan receivable (\$39 million)
Financing activities	(651)	(703)	52	Increase in borrowings under credit facilities (\$286 million), higher issuance of long-term debt (\$85 million), and higher proceeds on the sale of non-controlling interest in a subsidiary (\$144 million), partially offset by higher repayments of long-term debt (\$365 million), lower realized gains on financial instruments (\$58 million) and repurchase of common shares (\$23 million)
Translation of foreign currency cash	—	(1)	1	
Cash and cash equivalents, end of year	89	314	(225)	

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 instruments (\$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	

## 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 may 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 mainly used for cash flow 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 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.

### 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 may be 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.

Physical and financial swaps, forward sale and purchase contracts, futures contracts, and options may be 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 may be used to offset the exposures resulting from foreign-denominated long-term debt. Interest rate swaps may be 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 other comprehensive income ("OCI"). These gains or losses are subsequently reclassified from OCI to net earnings in the same period as the hedged forecast cash flows impact net earnings, and offset the losses or gains arising from the forecast transactions. For project hedges, the gains and losses reclassified from OCI are included in the carrying amount of the related PP&E.

Under IFRS 9, which we adopted on Jan. 1, 2018, hedge accounting requirements were simplified, to introduce a more principles based approach for qualifying hedges, aligned with an entity's approach to risk management, and to revise and simplify the hedge effectiveness requirements.

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

### Net Investment Hedges

Foreign-denominated long-term debt is 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. 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 consolidated financial statements. At Dec. 31, 2018, Level III instruments had a net asset carrying value of \$695 million (2017 - \$771 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, 2017.

## 2019 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2019:

Measure	Target
Comparable EBITDA	\$875 million to \$975 million
FCF	\$270 million to \$330 million
Dividend	\$0.16 per share annualized, 14 to 17 per cent payout of FCF
<b>Range of key power price assumptions</b>	
Market	Power Prices (\$/MWh)
Alberta Spot	\$50 to \$60
Alberta Contracted	\$50 to \$55
Mid-C Spot (US\$)	\$20 to \$25
Mid-C Contracted (US\$)	\$47 to \$53
<b>Other assumptions relevant to 2019 financial outlook</b>	
Sustaining Capital	\$160 million to \$190 million
Productivity Capital	\$10 million to \$15 million
Sundance coal capacity factor	30%
Hydro/ Wind Resource	Long term average

### Operations

#### Availability and Capacity

Availability of our coal fleet is expected to be in the range of 87 to 89 per cent in 2019. Availability of our other generating assets (gas, renewables) is expected to be in the range of 92 to 96 per cent in 2019. We will be accelerating our transition to gas and renewables generation, and continue on our coal-to-gas conversion strategy as set out in the Significant and Subsequent Events section of this MD&A.

#### Market Pricing and Hedging Strategy

For 2019, power prices in Alberta are expected to be slightly higher than 2018 due to a full year of lower supply as a result of the mothballing and shutdown of certain coal-fired units in 2018. Pacific Northwest power prices for 2019 are expected to be lower than 2018 as 2018 prices were impacted by specific events that are not expected to occur in the future. Ontario power prices are expected to remain consistent with 2018 prices.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF which also provides for positive exposure to price volatility in Alberta. Given our cash operating costs, we can be more or less hedged in a given period, and we expect to realize our annual FCF targets through a combination of forward hedging and selling generation into the spot market.

**Fuel Costs**

In Alberta, we expect the 2019 cash fuel costs for coal to be slightly lower than the 2018 costs and total fuel costs to be lower due to increased co-firing with natural gas among the merchant units.

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. In 2017 we amended our fuel and rail contract such that our costs fluctuate partly with gas prices. The delivered fuel cost in 2019 is expected to be consistent with 2018 costs.

Most of our generation from gas is sold under contracts with pass-through provisions for fuel. For gas generation with no pass-through provisions, 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 2019 objective for Energy Marketing is for the segment to contribute between \$75 million to \$85 million in gross margin for the year.

**Exposure to Fluctuations in Foreign Currencies**

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

**Net Interest Expense**

Net interest expense for 2019 is expected to be lower than in 2018 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. In addition, interest expense will increase as a result of implementing IFRS 16. See the Accounting Changes section of this MD&A for further details.

**Liquidity and Capital Resources**

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to \$1.0 billion in liquidity including \$89 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 maturity in 2020.

## Capital Expenditures

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

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

Project	Total project		2019	Target completion date	Details
	Estimated spend	Spent to date <sup>(1)</sup>	Estimated spend		
Big Level wind development project <sup>(2)</sup>	214	84	130	Q3 2019	90 MW wind project with a 15-year PPA
Antrim wind development project <sup>(3)</sup>	97	25	72	Q3 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	90	15	75	Q4 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Windrise wind development project	270	—	47	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
<b>Total</b>	<b>671</b>	<b>124</b>	<b>324</b>		

(1) Represents amounts spent as of Dec. 31, 2018.

(2) The numbers reflected above are in CAD but the actual cash spend on this project is in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD\$165 million, spent to date is USD\$65 million and estimated total spend in 2019 is USD\$100 million. TransAlta Renewables will fund the construction costs using its existing liquidity and tax equity.

(3) The numbers reflected above are in CAD but the actual cash spend on this project is in USD and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is USD\$75 million, spent to date is USD\$19 million and expected total spend in 2019 is USD\$56 million. TransAlta Renewables will fund the acquisition and construction costs using its existing liquidity and tax equity. The project remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling.

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 2017	Spent in 2018	Expected spend in 2019
Routine capital <sup>(1)</sup>	Capital required to maintain our existing generating capacity	69	50	50 - 60
Planned major maintenance	Regularly scheduled major maintenance	121	58	70 - 80
Mine capital	Capital related to mining equipment and land purchases	28	42	20 - 25
Finance leases	Payments on finance leases	17	18	20 - 25
<b>Total sustaining capital</b>		<b>235</b>	<b>168</b>	<b>160 - 190</b>
Insurance recoveries of sustaining capital expenditures	Insurance proceeds related to the fire at Wyoming Wind and Canadian Coal equipment	—	(7)	—
<b>Total sustaining capital</b>		<b>235</b>	<b>161</b>	<b>160 - 190</b>
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	24	21	10 - 15
<b>Total sustaining and productivity capital</b>		<b>259</b>	<b>182</b>	<b>170 - 205</b>

(1) Includes hydro life extension expenditures.

Significant planned major outages at TransAlta's operated units for 2019 include the following:

- two outages for major maintenance at Keephills Unit 1 and Sundance Unit 4 within our Canadian Coal segment during Q1 and Q2 2019;
- one major outage in our Canadian Gas segment related to our Sarnia facility during Q2 2019;
- distributed planned maintenance expenditures across the entire Hydro fleet; and
- distributed expenditures across our wind fleet, focusing on planned component replacements.

Lost production as a result of planned major maintenance, excluding planned major maintenance for US Coal, which is scheduled during a period of dispatch optimization, is estimated as follows for 2019:

	Coal	Gas and renewables	Total
GWh lost	500 - 550	400 - 450	900 - 1,000

### Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities and existing liquidity. We have access to approximately \$1.0 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 our monitoring controls, long-range forecasts are prepared for each Cash Generating Unit ("CGU"). The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide a criteria to evaluate adverse changes in operations. When indicators of impairment are present, we estimate a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to our long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices, and useful lives of the assets.

### Alberta Merchant CGU

During 2018, 2017, and 2016, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan, 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 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 2018, 2017, and 2016, due to the Corporation's large merchant renewable fleet in the province.

### 2018

#### *Sundance Unit 2*

In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of \$38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years 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 July 31, 2018. Discounting did not have a material impact.

#### *Lakeswind and Kent Breeze*

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze. In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of \$12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an \$11 million impact on PP&E, and a \$1 million impact on Intangible assets.

### 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 maintained the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU to 2021.

## 2016

### 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. 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.

### Project Development Costs

During 2018, the Corporation wrote-off \$23 million in project development costs related to projects that are no longer proceeding.

### 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, 2018, we provided letters of credit totaling \$720 million (2017 - \$677 million) and cash collateral of \$105 million (2017 - \$67 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:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Natural gas, transportation, and other purchase contracts	28	15	13	11	12	157	236
Transmission	9	10	6	4	3	—	32
Coal supply and mining agreements <sup>(1)</sup>	158	160	27	24	24	95	488
Long-term service agreements	64	86	32	17	8	34	241
Non-cancellable operating leases <sup>(2)</sup>	8	8	8	7	4	45	80
Long-term debt <sup>(3)</sup>	130	486	91	947	141	1,439	3,234
Principal payments on finance lease obligations	18	16	9	5	5	10	63
Interest on long-term debt and finance lease obligations <sup>(4)</sup>	161	152	129	123	84	694	1,343
Growth	324	79	144	—	—	—	547
TransAlta Energy Transition Bill	6	7	6	6	6	—	31
<b>Total</b>	<b>906</b>	<b>1,019</b>	<b>465</b>	<b>1,144</b>	<b>287</b>	<b>2,474</b>	<b>6,295</b>

(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.

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement ("MoA"), we have committed to fund US\$55 million in total 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 MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required. As at Dec. 31, 2018, the Corporation has funded approximately US\$33 million of the commitment.

## Contingencies

### Line Loss Rule Proceeding

TransAlta has been participating in a line loss rule proceeding before the Alberta Utilities Commission ("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 current estimate of exposure based on known data is \$15 million and therefore the Corporation increased the provision from \$7.5 million to \$15 million in 2018.

### FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

### Balancing Pool Dispute

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately \$157 million on March 29, 2018 as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional \$56 million. The dispute is currently proceeding through arbitration.

## 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 annual audited 2018 consolidated financial statements. 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

### Revenue from Contracts with Customers

The Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018. The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are active at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). The Corporation's accounting policies for the current and prior periods for revenue recognition are outlined in Note 2 of the annual audited 2018 consolidated financial statements. The significant judgments and estimates have been highlighted below.

The majority of our revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, renewable attributes and byproducts of power generation. The Corporation evaluates whether the contracts it enters into meet the definition of a contract with a customer at the inception of the contract and on an ongoing basis if there is an indication of significant changes in facts and circumstances. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the Corporation's performance to date. The Corporation excludes amounts collected on behalf of third parties from revenue.

#### *Identification of Performance Obligations*

Each promised good or service is accounted for separately as a performance obligation if it is distinct. The Corporation's contracts may contain more than one performance obligation.

Where contracts contain multiple promises for goods or services, management exercises judgment in determining whether goods or services constitute distinct goods or services or a series of distinct goods or services that are substantially the same and that have the same pattern of transfer to the customer. The determination of a performance obligation affects whether the transaction price is recognized at a point in time or over time. Management considers both the mechanics of the contract and the economic and operating environment of the contract in determining whether the goods or services in a contract are distinct.

#### *Transaction Price*

The Corporation allocates the transaction price in the contract to each performance obligation. Transaction price allocated to performance obligations may include variable consideration. Variable consideration is included in the transaction price for each performance obligation when it is highly probable that a significant reversal of the cumulative variable revenue will not occur. Variable consideration is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Corporation's contracts with customers is primarily variable, and may include both variability in quantity and pricing, such as: revenues can be dependent upon future production volumes which are driven by customer or market demand or by the operational ability of the plant; revenues can be dependent upon the variable cost of producing the energy; revenues can be dependent upon market prices; and revenues can be subject to various indices and escalators.

In determining the transaction price and estimates of variable consideration, management considers past history of customer usage and capacity requirements, in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets.

#### *Allocation of Transaction Price to Performance Obligations*

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Corporation expects to be entitled to in exchange for transferring the good or service.

The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

*Satisfaction of Performance Obligations*

The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient can be relied upon in measuring progress toward complete satisfaction of performance obligations. The invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

The Corporation recognizes a significant financing component where the timing of payment from the customer differs from the Corporation's performance under the contract and where that difference is the result of the Corporation financing the transfer of goods and services.

**Revenue from Other Sources***Lease Revenue*

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. 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.

*Revenue from Derivatives*

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.

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 described below.

**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.

Our Commodity Exposure Management Policy, 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 for contracts included in the Level III fair value measurements at Dec. 31, 2018, is an estimated total upside of \$150 million (2017 - \$156 million upside) and total downside of \$150 million (2017 - \$157 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of \$116 million upside (2017 - \$130 million upside) and \$116 million downside (2017 - \$130 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\$20-US\$35 (Dec. 31, 2017 - US\$25-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. The 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. No changes arose in our CGUs in 2018.

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. As a result of our review in 2018 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.

### 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 2018, total depreciation and amortization expense was \$710 million (2017 - \$708 million, 2016 - \$664 million), of which \$136 million (2017 - \$73 million, 2016 - \$63 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 the 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 2018, 2017 and 2016 annual goodwill impairment reviews, the Corporation determined the recoverable amounts of the CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy.

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

Determining the fair value of the CGUs or group of CGUs is susceptible to changes from period to period as management is required to make assumptions about future cash flows, production and trading volumes, margins, and fuel and operating costs. No reasonably possible change in the assumptions would have resulted in an impairment of goodwill.

### Leases

In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfilment 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 \$28 million (2017 - \$24 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2018. 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 \$501 million (2017 - \$549 million) have been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2018. 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, 2018, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were \$407 million (2017 - \$437 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 2019 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	4
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

### Current Accounting Changes

#### **IFRS 15 Revenue from Contracts with Customers**

We adopted IFRS 15 *Revenue from Contracts with Customers* with an initial adoption date of Jan. 1, 2018.

We elected to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the annual audited 2018 consolidated financial statements will not be restated, and comparative period revenues continue to be reported as recognized following IAS 18 *Revenue*. Instead of restating prior years' revenues, we recognized the cumulative impact of the initial application of the standard in the deficit as at Jan. 1, 2018. The cumulative impact of applying the significant financing component requirements of IFRS 15 to an impacted contract resulted in a \$13 million (net of tax impacts) increase to the deficit, an increase to the contract liability of \$17 million, and a decrease in deferred income tax liabilities of \$4 million.

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.

Additionally, we no longer recognize revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of our gas plants, as it was determined under IFRS 15 that we do not obtain control of the customer-supplied natural gas. This change had no impact on the cumulative impact of initial adoption as recognized in Deficit at Jan. 1, 2018.

Note 2 and Note 3, respectively, of our annual audited 2018 consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 15 and our adoption of IFRS 15.

#### **IFRS 9 Financial Instruments**

Effective Jan. 1, 2018, we adopted IFRS 9, which introduces new requirements for:

- the classification and measurement of financial assets and financial liabilities;
- the recognition and measurement of impairment of financial assets; and
- a new hedge accounting model.

In accordance with the transition provisions of the standard, we elected to not restate prior periods' comparative financial statements.

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 at fair value through other comprehensive income. 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. While the Corporation had no direct impact of adoption the IFRS 9 classification and measurement requirements, a \$1 million increase in the deficit resulted from the increase in equity attributable to non-controlling interests due to the IFRS 9 classification and measurement impacts at TransAlta Renewables.

IFRS 9 introduces a new impairment model for financial assets measured at amortized cost. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk. The loss allowance for a financial

asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss. The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon 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 and introduces new effectiveness testing requirements focused on the principle of an economic relationship and eliminates the requirement for retrospective assessment of hedge effectiveness. The Corporation's qualifying hedging relationships in place as at Jan. 1, 2018, also qualified for hedge accounting in accordance with IFRS 9 and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018.

Note 2 and Note 3, respectively, of our annual audited 2018 consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 9 and our adoption of IFRS 9.

### 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, 2018, the useful lives of some of the Corporation's mine assets were adjusted to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense included in fuel and purchased power increased in total by approximately \$38 million. 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 was shut down two years early, the Canadian federal Minister of Environment and Climate Change 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.

### 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:

#### 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. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. For lessors, the accounting remains essentially unchanged.

IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019. The standard is required to be adopted either retrospectively or using a modified retrospective approach. On transition, TransAlta has elected to apply IFRS 16 using the modified retrospective approach effective Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and low value leases;
- Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;

- Adjusting the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right-of-use assets at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

The Corporation has substantially completed its assessment of existing operating leases. The Corporation estimates that we will recognize right-of-use lease assets and related lease liabilities for existing operating leases where we are the lessee in the range of \$42 million to \$52 million. These changes will be partially offset by the derecognition of a finance lease asset and a finance lease liability related to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16.

## Competitive Forces

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

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

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

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

### Alberta

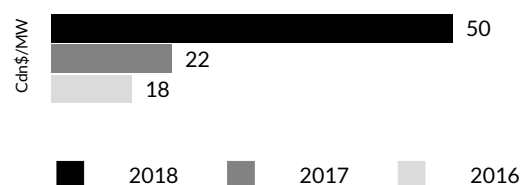
Approximately 58 per cent of our gross installed capacity is located in Alberta and approximately 50 per cent of this is subject to legislated Alberta PPAs, which were put in place in 2001 to facilitate the transition from regulated generation to the current energy market in the province. The Sundance 1 and 2 Alberta PPAs expired at the end of 2017, the Sundance 3 to 6 PPAs were terminated effective March 31, 2018, and the Keephills 1 and 2, Sheerness and Hydro PPAs will expire at the end of 2020. The Balancing Pool acts as buyer for the Keephills and Sheerness PPAs as a result of the terminations in 2016 by the original buyers.

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, and we announced updates to this in December 2018. 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.

Alberta's annual demand increased approximately 3 per cent from 2017 to 2018. The increase in demand was reflected in the average pool price, which increased from \$22.19/MWh in 2017 to \$50.29/MWh in 2018. The majority of the pool price increase was due to higher carbon compliance costs from thermal generation. The higher prices also positively impacted our merchant wind and hydro portfolio.

### Average Spot Electricity Prices



Our market share of offer control in Alberta in 2018 was 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 an OCA with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal. We also entered into a Memorandum of Understanding 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.

Pursuant to the *Electric Utilities Act* (Alberta), the Balancing Pool announced the complete termination of the Sundance 3 to 6 PPAs, effective March 31, 2018. As of April 1, 2018, the Sundance plant has been operated as a merchant facility. There has been no announcement yet concerning the Keephills PPA.

TransAlta continues to operate the Keephills PPA generating units in their ordinary course and receives the capacity and energy payments due to TransAlta under the PPAs.

**Coal-to-Gas Conversions**

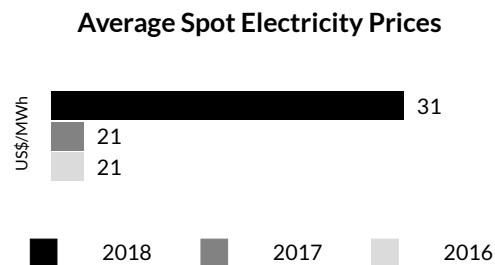
On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The final regulation provides specific provisions for coal-to-gas conversions. The rules for converted units will allow converted plants to operate 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.

We are planning the conversion of the units at Sundance and Keephills to gas-fired generation in the 2020 to 2023 time frame. The conversions will provide competitive, reliable, low-cost power to the Alberta market and are expected to position them well in the proposed capacity market. We expect the first capacity auction to occur in 2020 for delivery in November 2021.

In July 2018, we retired the then mothballed Sundance Unit 2 due to its shorter useful life relative to other units, age, size and the capital requirements needed to return the unit to service.

**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 has added to the downward pressure on power prices.

Our competitiveness is enhanced by our long-term contract with Puget Sound Energy for up to 380 MW over the remaining life of the facility. The contract and our hedges allow us to satisfy power requirements from the market during low-priced periods.

We maintain the right to redevelop Centralia as a gas plant after coal capacity retires, with an opportunity for expedited 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), Parkeston (2026 expiry) and Fort Saskatchewan (2030 expiry) plants in this manner.

## TransAlta's Capital

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

### Financial Capital

Our goal over the last few years was to build financial flexibility by using multiple sources of funding to reposition our capital structure. Over the last few years, the rating of our unsecured debt was put under pressure by all the rating agencies. 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. In June 2018 Moody's revised its rating outlook to positive from stable. During 2018, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a negative outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing. 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. Risks associated with 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:

As at Dec. 31	2018		2017		2016	
	\$	%	\$	%	\$	%
TransAlta Corporation						
Recourse debt - CAD debentures	647	9	1,046	14	1,045	12
Recourse debt - US senior notes	943	13	1,499	19	2,151	25
Credit facilities	174	2	—	—	—	—
US tax equity financing	28	—	31	—	39	—
Other	11	—	13	—	15	—
Less: cash and cash equivalents	(16)	—	(294)	(4)	(290)	(3)
Less: principal portion of restricted cash on TransAlta OCP	(27)	—	—	—	—	—
Less: fair value asset of economic hedging instruments on debt <sup>(1)</sup>	(10)	—	(30)	—	(163)	(2)
Net recourse debt	1,750	24	2,265	29	2,797	32
Non-recourse debt	469	6	208	3	245	3
Finance lease obligations	63	1	69	1	73	1
<b>Total consolidated net debt - TransAlta Corporation</b>	<b>2,282</b>	<b>31</b>	<b>2,542</b>	<b>33</b>	<b>3,115</b>	<b>36</b>
TransAlta Renewables						
Credit facility	165	2	27	—	—	—
Less: cash and cash equivalents	(73)	(1)	(20)	—	(15)	—
Net recourse debt	92	1	7	—	(15)	—
Non-recourse debt	767	11	814	11	793	9
<b>Total consolidated net debt - TransAlta Renewables</b>	<b>859</b>	<b>12</b>	<b>821</b>	<b>11</b>	<b>778</b>	<b>9</b>
<b>Total consolidated net debt</b>	<b>3,141</b>	<b>43</b>	<b>3,363</b>	<b>44</b>	<b>3,893</b>	<b>45</b>
Non-controlling interests	1,137	16	1,059	14	1,152	14
Equity attributable to shareholders						
Common shares	3,059	42	3,094	40	3,094	36
Preferred shares	942	13	942	12	942	11
Contributed surplus, deficit and accumulated other comprehensive income	(1,004)	(14)	(710)	(9)	(525)	(6)
<b>Total capital</b>	<b>7,275</b>	<b>100</b>	<b>7,748</b>	<b>100</b>	<b>8,556</b>	<b>100</b>

(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.

We continued strengthening our financial position during 2018 and have reduced our total consolidated net debt by almost \$800 million since the end of 2016 and enhanced shareholder value by:

### 2018:

- early redeeming our outstanding 6.650 per cent US\$500 million senior notes due May 15, 2018, for approximately \$617 million (US\$516 million) using proceeds from the Sundance B and C PPAs termination payment and existing liquidity;
- early redeeming our outstanding 6.40 per cent \$400 million debentures due Nov. 2019, for approximately \$425 million;
- paying out the US\$25 million non-recourse debt related to the Mass Solar projects;
- purchasing and cancelling 3,264,500 common shares at an average price of \$7.02 per share through our NCIB program, for a total cost of \$23 million;

### 2017:

- making a scheduled US\$400 million 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; and
- early redeeming all of Canadian Hydro Developers Inc.'s ("CHD") outstanding non-recourse debentures.

See the Significant and Subsequent Events section of this MD&A for further details.

Throughout 2016, 2017 and 2018, we continued implementing our strategy to raise debt secured by our contracted cash flows and completed the following debt offerings:

- a non-recourse bond in the amount of \$345 million on July 20, 2018, with principal and interest payable semi-annually, maturing on Aug. 5, 2030, secured by the payments we receive under the OCA;
- a project-level bond in the amount of \$260 million on Oct. 2, 2017, with principal and interest payable quarterly, maturing on Nov. 30, 2033, secured by our Kent Hills wind farm;
- a non-recourse bond in the amount of \$202.5 million on Dec. 7, 2016, with principal and interest payable quarterly, maturing on Dec. 31, 2030, secured by our Poplar Creek finance lease contract; and
- a non-recourse bond in the amount of \$159 million on June 3, 2016, 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.

Between 2019 and 2021, we have approximately \$707 million of debt maturing. We expect to continue our deleveraging strategy over the next three years as part of our balanced capital allocation plan.

The strengthening of the US dollar has increased our long-term debt balances by \$76 million as at Dec. 31, 2018. Almost all our US-denominated debt is hedged either through financial contracts or net investments in our US operations. During the period, these changes in our US-denominated debt were offset as follows:

As at Dec. 31	2018	2017
Effects of foreign exchange on carrying amounts of US operations (net investment hedge) <sup>(1)</sup> and finance lease receivable	42	(43)
Foreign currency cash flow hedges on debt	11	(45)
Economic hedges and other	21	(18)
Unhedged	2	(7)
<b>Total</b>	<b>76</b>	<b>(113)</b>

*(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.*

Our credit facilities provide us with significant liquidity. At Dec. 31, 2018, we had \$2.0 billion (2017 - \$2.0 billion) of committed credit facilities, of which \$0.9 billion (2017 - \$1.4 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2018, the \$1.1 billion (2017 - \$0.6 billion) of credit utilized under these facilities was comprised of actual drawings of \$0.3 billion (2017 - nil) and letters of credit of \$0.7 billion (2017 - \$0.6 billion). These facilities are comprised of a \$1.3 billion committed syndicated bank facility expiring in 2022, TransAlta Renewables \$500 million committed syndicated bank credit facility expiring in 2022, and three bilateral credit facilities, totalling \$240 million, expiring in 2020.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and OCP non-recourse bonds with a carrying value of \$1,235 million (Dec. 31, 2017 - \$1,022 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 can 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 2019. At Dec. 31, 2018, \$33 million (Dec. 31, 2017 - \$35 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, 2018.

#### *Working Capital*

Including the current portion of long-term debt, the excess of current assets over current liabilities was \$439 million as at Dec. 31, 2018 (2017 - \$101 million). Our working capital increased year over year mainly due to a decrease in long-term debt due within the next year (last year, we had a US\$500 million senior note due). Excluding the current portion of long-term debt of \$148 million, the excess of current assets over liabilities was \$587 million as at Dec. 31, 2018 (2017 - \$848 million), a decrease of \$261 million, mainly due to the lower cash and cash equivalents and trade and other receivables.

*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 tables outline the common and preferred shares issued and outstanding:

As at	Feb. 26, 2019	Dec. 31, 2018	Dec. 31, 2017
	Number of shares (millions)		
<b>Common shares issued and outstanding, end of period</b>	<b>284.6</b>	<b>284.6</b>	<b>287.9</b>
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
<b>Preferred shares issued and outstanding, end of period</b>	<b>38.6</b>	<b>38.6</b>	<b>38.6</b>

*Non-Controlling Interests*

As of Dec. 31, 2018, we own 60.9 per cent (2017 – 64.0 per cent) of TransAlta Renewables. In 2018, our ownership percent decreased due to TransAlta Renewables issuing approximately 12 million common shares under a bought deal offering and approximately one million common shares under their Dividend Reinvestment Plan. We did not participate in either of these issuances.

In 2017, the South Hedland Power Station achieved commercial operation on July 28, 2017, and 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.

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 Sarnia, Ragged Chute and Le Nordais by TransAlta Renewables.

TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol "RNW". TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

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 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	2018	2017	2016
Interest on debt	184	218	218
Interest income	(11)	(7)	(2)
Capitalized interest	(2)	(9)	(16)
Loss on redemption of bonds	24	6	1
Interest on finance lease obligations	3	3	3
Credit facility fees, bank charges, and other interest	13	18	19
Keephills 1 outage interest accruals (reversals)	—	—	(10)
Other <sup>(1)</sup>	15	(3)	(4)
Accretion of provisions	24	21	20
<b>Net interest expense</b>	<b>250</b>	<b>247</b>	<b>229</b>

(1) During 2018, approximately \$5 million of costs were expensed due to project level financing that is no longer practicable and approximately \$7 million relates to the significant financing component required under IFRS 15.

Although interest on debt was down due to lower debt levels, net interest expense was higher in 2018 due to the \$5 million prepayment premium relating to the early redemption of the US\$500 million senior notes, \$5 million of costs expensed in connection to a project-level financing that is no longer practicable, the \$19 million prepayment premium relating to the early redemption of the \$400 million debenture and lower capitalized interest.

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.

### 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 common and preferred shares dividends declared each quarter during 2018:

Declaration date	Payable date		Common dividends per share	Preferred Series dividends per share				
	Common shares	Preferred shares		A	B	C	E	G
Feb 2, 2018	Apr 1, 2018	Mar 31, 2018	0.04	0.16931	0.17889	0.25169	0.32463	0.33125
Apr 19, 2018	Jul 3, 2018	Jul 3, 2018	0.04	0.16931	0.19951	0.25169	0.32463	0.33125
Jul 19, 2018	Oct 1, 2018	Sept. 30, 2018	0.04	0.16931	0.20984	0.25169	0.32463	0.33125
Oct 10, 2018	Jan 1, 2019	Dec 31, 2018	0.04	0.16931	0.22301	0.25169	0.32463	0.33125
Dec 14, 2018	Apr 1, 2019	Mar 31, 2019	0.04	0.16931	0.23073	0.25169	0.32463	0.33125

### Non-Controlling Interests

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2018, increased \$66 million to \$108 million compared to 2017. Earnings were up at TransAlta Renewables in 2018 due to higher finance income from its investment in the Australian business and the 2017 impairment of an investment. Earnings from TA Cogen were lower in 2018 mainly due to the settlement of the contract indexation dispute with the OEFC relating to the Ottawa and Windsor facilities positively impacting 2017 earnings.

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.

## Power-Generating Portfolio Capital

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

### Availability and Production

Our availability target for our Canadian Coal fleet was 87 to 89 per cent for 2018. We achieved 93 per cent availability in Canadian Coal. Our availability target for our other generating assets (gas and renewables) was in the range of 95 per cent in 2018. Canadian Gas achieved 93 per cent, Australian Gas 94 per cent and Wind and Solar exceeded 95 per cent at 95.4 per cent.

Our availability for the entire fleet in 2018, after adjusting for dispatch optimization at US Coal, was 91.3 per cent (2017 - 86.8 per cent, 2016 - 89.2 per cent) and was improved over last year. Lower outages and derates at Canadian Coal and higher availability at Canadian Gas due to lower outages were partially offset by the impact of unplanned outages and derates at US Coal in the latter half of the year.

Production for the year ended Dec. 31, 2018, decreased 8,491 GWh compared to 2017. The decrease was mainly at Canadian Coal where production decreased 8,229 GWh primarily due to the mothballing and retirement of certain Sundance units. Production at US Coal was down 104 GWh due to the timing of dispatch optimization. Production at Wind and Solar was also down by 92 GWh mainly due to lower wind resources in Alberta and the United States, partially offset by higher wind resources in Eastern Canada.

### Adjusted Availability (%)



### Production (GWh)



### 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. Savings achieved in Canadian Coal, Mining and Canadian Gas were offset by increased costs from US Coal and Australian Gas. Increases in OM&A are detailed in the Segmented Comparable Results section of this MD&A.

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

Year ended Dec. 31	2018	2017	2016
<b>Generation comparable OM&amp;A</b>	<b>405</b>	<b>412</b>	<b>396</b>
Greenlight transformation costs included in OM&A:			
Canadian Coal	(6)	(20)	—
US Coal	(2)	(2)	—
Gas, Wind and Solar, and Hydro	(5)	(7)	—
<b>Adjusted generation comparable OM&amp;A</b>	<b>392</b>	<b>383</b>	<b>396</b>

### 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	2018	2017	2016
Routine capital	50	69	83
Mine capital	42	28	23
Planned major maintenance	58	121	148
Finance leases	18	17	16
<b>Total sustaining capital expenditures</b>	<b>168</b>	<b>235</b>	<b>270</b>
Productivity capital	21	24	8
Flood-recovery capital	–	–	2
<b>Total sustaining and productivity capital expenditures</b>	<b>189</b>	<b>259</b>	<b>280</b>
Insurance recoveries of sustaining capital expenditures	(7)	–	(1)
<b>Net amount</b>	<b>182</b>	<b>259</b>	<b>279</b>

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

Year ended Dec. 31	2018	2017	2016
GWh lost <sup>(1)</sup>	381	1,234	938

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

Total sustaining capital expenditures were \$67 million lower compared to 2017 and total productivity capital was \$3 million lower in 2018 compared to 2017. The productivity capital expenditures relate to the funding of some Project Greenlight transformation initiatives. In certain cases, payback is expected to be achieved within three years. We also completed planned major outages at Genessee Unit 3, Centralia Unit 2 and Sarnia.

### Strategic Growth and Corporate Transformation

#### Acquisition of Two US 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. Construction of the projects has started. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level") and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the acquisition to close in early 2019. See the Significant and Subsequent Events section of this MD&A for further details.

#### Kent Hills Wind Farm

During 2017, TransAlta Renewables entered into a 17-year power purchase agreement with NB Power for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills wind farm. On Oct. 19, 2018, TransAlta Renewables announced that the expansion is fully operational, bringing total generating capacity of the Kent Hills wind farm to 167 MW.

#### Pioneer Gas Pipeline Partnership

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer Pipeline. Tidewater will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline is expected to provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately \$90 million. Construction of the pipeline commenced in November 2018 and it is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals.

**Windrise Wind Project**

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the two successful projects in the third round of the Renewable Electricity Program. The Windrise project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta. The project is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO and is expected to cost approximately \$270 million and is targeted to reach commercial operation during the second quarter of 2021.

**Brazeau Hydro Pumped Storage**

The Brazeau Hydro Pumped Storage project will generate and support clean electricity in the Province of Alberta. 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. The Brazeau Hydro Pumped Storage project is a priority 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.

The Brazeau Hydro Pumped Storage project is expected to have new capacity up to 900 MW, bringing the total Brazeau facility from 755 MW to 1,255 MW, post-completion. We estimate an investment in the range of \$1.5 billion to \$2.7 billion. During the first nine months of 2018, we invested approximately \$2 million to advance the environmental study, work with stakeholders and execute geotechnical work to help further our design and construction phase. Further advancement of the project is dependent on securing a long-term contract.

In May 2018, the AESO released a report stating that dispatchable renewable resources are not needed in the Alberta market before 2030. The value and benefit of the Brazeau Hydro Pumped Storage project would be well beyond the 2030 period. The Corporation still believes that generation from pumped storage should be part of future calls for power under the Alberta Renewables program. The Corporation is not spending additional development dollars on the project at this time but will continue to work with governments to find the appropriate financial mechanisms for bringing low-cost, green, dispatchable renewables into the market to support low prices and emissions for Alberta customers.

**Project Greenlight**

Project Greenlight is a multi-year program to transform our business and the delivery of the Corporation's strategy. Business units are focusing both on cash flow improvements and the way the Corporation is delivering sustainable value.

Through this program we delivered on projects that improved performance by improving generation efficiency, improving heat rates, lowering fuel costs, reducing GHG emissions, reducing operating and maintenance costs, optimizing our capital spend, avoiding new costs, reducing overhead costs and financing costs, improving working capital, monetizing assets, streamlining processes and achieving efficiencies. Value savings were offset by current year program costs and project costs, made up of mostly capital expenditures. We estimate that the Project Greenlight initiatives generated net \$70 million in gross margin, OM&A expense and capital savings. This enabled financial flexibility for new investments. We invested approximately \$16 million (2017 - \$29 million) in this program and an additional \$21 million (2017 - \$25 million) in productivity capital in 2018.

**Contractual Profile**

Approximately 70 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 contracted until 2042.

**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 having an engaged workforce and keeping our employees safe.

As at Dec. 31, 2018, we had 1,883 (2017 - 2,228) active employees. This number has decreased by fifteen per cent over 2017, following reduction in positions at our coal fleet and restructuring initiatives to reduce costs and increase efficiency. A number of unfilled positions have also been eliminated.

With approximately 50 per cent of our employees being unionized, we strive to maintain open and positive relationships with union representatives and regularly meet to exchange information, listen to concerns and share ideas that further our mutual objectives. Collective bargaining is conducted in good faith, and we respect the rights of all employees to participate in collective bargaining.

### Organizational Culture and Structure

Our employees are central to 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 as a business-centric model, with Coal & Mining, Gas & Renewables, Australia, and Energy Marketing & Trading defined as our four primary businesses. Our Corporate function oversees our business and provides strategic alignment.

### Gender Diversity

A number of case studies have highlighted the link between gender diversity and additional business value. TransAlta is an active supporter of gender diversity as a driver for value, but also as an ethical business practice. Our commitment to increased female participation in our business is evidenced by our female participation rates on both our executive and Board. As at Dec. 31, 2018, women made up 50 per cent of our executive team and 40 per cent of our Board. This is well above our peers in the electricity sector. The Canadian Electricity Association reported that averages for women in executive and on Boards in 2017 was 25.5 and 31.5, per cent respectively. This is also well above the Catalyst Accord, which is signed by a number of leading organizations in Canada, that all support targets to ensure women comprise 30 per cent of executive and Board roles by 2022.

Year ended Dec. 31	TransAlta (per cent)	Industry average (per cent)	Catalyst Accord targets (per cent)
Women on executive team	50	25	30
Women on Board	40	31	30

### 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 exceeded 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 Canadian retiree benefits plan was closed for all new hired employees as of March 1, 2017. 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 viewed as a key pillar of organizational health. In 2018, we extended our Change Leadership Forum to our managers, building upon senior management training in 2017. The two-day session is focused on organizational transformation with an emphasis on identifying root causes of barriers related to driving change.

In 2018, we completed a six-month peer lead leadership training program, called Elevate, for our professionals and subject matter experts. This builds on training of 75 middle management professionals in 2017. The program is 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 addition to Elevate, we continued our two-day leadership program in 2018 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. To date, approximately 830 employees (or 44 per cent) have taken this course. Employees learn project management (i.e., idea generation, planning, problem solving and prioritization), effective communication (i.e., presentations, meetings and emails), how to get the best out of people (coaching and influencing) and health (organizational health and personal resilience).

In addition, we seek unique ways to expose employees to energy transformation and disruption. Employees are encouraged to target development in areas to support this. In 2018, we sent 25 of our employees to the Energy Disruptors conference in Calgary, which was highlighted by Richard Branson as a keynote. Learning from global leaders working on the energy transition, this group returned to integrate ideas and solutions into our business, through our Project Greenlight program.

### 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 when we added to our work on occupational safety with a renewed focus on process safety. In collaboration with ScottishPower, an organization known for achieving leading safety performance, we launched our Total Safety Management System. The management system 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. Our Total Safety Management System adds a focus on preventing incidents from our equipment and processes through definition and measurement of safety-critical performance measures and operating limits.

In 2018, the first full year of implementation of a safety culture transformation within our Coal and Mining business was completed. The bulk of the Canadian Coal employees were provided with new tools and capability to improve their own personal safety and that of their workmates. In addition there have been improvements in safety standards, amenities, housekeeping and safety leadership implemented in parallel.

This combination of initiatives has led to progress and results. In 2018 our Injury Frequency Rate ("IFR") was 0.54 (2017 - 0.72). 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. Our target IFR in 2019 is 0.43, a 20 per cent reduction over 2018 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 injury avoidance. Our TIF in 2018 was 1.98, which was a 44 per cent improvement over 2017 performance. We are targeting a TIF of 1.58 in 2019, a 20 per cent reduction over 2017 performance. As noted above, our long-term goal is zero.

Year ended Dec. 31	2018	2017	2016
IFR	0.54	0.72	0.85
TIF	1.98	3.54	—

On December 29, 2018, we were notified of an incident that occurred and resulted in the fatality of an employee of Coalview Centralia LLC, which operates a fine coal recovery project within the Centralia mine site. Coalview Centralia LLC is a company that provides reclamation services to TransAlta and is not otherwise affiliated with the Corporation. We are all

deeply saddened by this situation and our thoughts and prayers are with the families, co-workers and friends impacted. Safety is an integral value at TransAlta and we continue to work every day to make our work environments safe.

We reward our business units for safety leadership annually at our President's Awards. This year the award for Safety Leadership and Performance was given to our Hydro fleet for achieving target zero in 2018. No medical aids and injuries occurred in 2018, despite 145,000 exposure hours while operating 27 facilities. It was a fantastic achievement from our Hydro business unit and provides inspiration for our other business units.

## Intellectual Capital

At TransAlta we define intellectual capital as our knowledge-based assets. Measuring these assets serves two purposes. First, we seek to understand our knowledge-based assets to improve our management and performance of these assets. Second, we seek to understand these assets to communicate their real value. The following highlights some of our knowledge-based assets, which we believe provide us with a competitive edge and that contribute to shareholder value.

### Brand Recognition

Our employee culture is supported by a purpose-based, long-term and sustainable business strategy, which is growth in affordable and clean power generation. TransAlta has operated power generation assets for over 100 years, which reflects this approach to long-term and sustainable business. A long-term commitment to business and partnerships 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.

### Diversified Knowledge

The experience and acumen of our employees further enhances our capital value creation. Our business has been operating for over 100 years, and many of our employees have been with us for 30 plus years.

Our experience in developing and operating power generation technologies is highlighted below. The transition of our coal assets to natural gas is a natural fit with our operating experience. Relative to coal, gas operations have lower operating costs, have increased operating reliability and flexibility, require less manpower and reduce GHG and air emissions. Our trading and marketing business complements our knowledge of operating power generation assets.

Power generation type	Operating experience (years)
Hydro	107
Natural Gas	68
Coal	68
Wind	16
Solar	3

### Innovation: Idea Generation and Project Management

We believe that global marketplace disruption is a new normal and we recognize that to adapt to the pace of change and remain competitive, our employees and processes must be nimble, adaptive and supporting working more efficiently, while at speed. 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.

This is evidenced by our ongoing internal transformation, called Project Greenlight, which is entering its third year since implementation. 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 spent considerable time educating and training our employees to both think differently and then manage their business case from idea to delivering sustained value. Year three is the final year of the project and we plan to transition Project Greenlight into the business as a sustained process.

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.

### **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 are now one of the largest wind generators 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 2025, 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 90 MW Big Level and 29 MW Antrim wind development projects in the US, the 207 MW Windrise wind development project in Alberta, proposed solar development on our reclaimed mine site at our Centralia facility in Washington State, and the exploration of hydro expansion.

We are keeping 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 more information on innovation at TransAlta, please visit [www.transalta.com/about-us/innovation](http://www.transalta.com/about-us/innovation).

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 key operational risks and implementing 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 2018 to an IFR of 0.54 (2017 - 0.72). 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.

### **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 on our social and relationship performance are public health and safety, anti-competitive behaviour and fostering better relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners where we operate.

#### **Public Health and Safety**

We seek to ensure public health and safety through measures that include restricting physical access to our operating sites and minimizing our environmental impact. It is our goal to keep safe our employees and the peoples and communities where we operate.



We specifically look to minimize the following risks:

- harm to person(s),
- damage to property,
- increased liability due to negligence, and
- loss of organizational reputation and integrity.

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 2018, we had two mercury exceedance events at our Centralia coal plant and one NOx stack breach at our Sundance facility. All of the events were captured through our monitoring systems and resolved quickly as a result. These incidents were all reported to regulatory bodies and were deemed to be minor.

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, we expect future GHG emissions and air pollution emissions performance will be dramatically reduced in respect of our existing assets as we execute our coal-to-gas conversion strategy. GHG emissions from coal are expected to be cut within the range of 60 per cent or 12 million tonnes carbon dioxide equivalent (CO<sub>2</sub>e). We currently capture 80 per cent of mercury emissions at our coal plants and mercury emissions will be eliminated following the coal-to-gas conversion. Particulate matter and sulphur dioxide emissions will be virtually eliminated or considered negligible post-coal-to-gas conversion 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 fulfill TransAlta's principles for engagement and ensure we live up to its commitments with Indigenous neighbours. Efforts are focused on building and maintaining solid relationships and establishing strong communication channels that enable TransAlta to share information on operations and growth initiatives, gather feedback to inform project planning and understand priorities and interests to better address concerns.

Specifically, our Aboriginal Relations team continues to develop and enhance aboriginal relations in areas of employment, economic development, community engagement, and investment.

Each year, TransAlta provides seven \$3,000 bursaries for post-secondary and three \$1,000 bursaries for trades students to support the success of Indigenous students in their educational programs. TransAlta's criteria for accessing the bursary includes any educational pursuit that will support the wellbeing of Indigenous peoples and communities. The bursary is open to all Indigenous applicants that have completed high school. Through agreements and ongoing relationship commitments TransAlta makes information on employment positions available to Indigenous communities and provides sub-contractors terms and conditions to include Indigenous content considerations for procurement initiatives.

In 2017, we once again achieved the Canadian Council for Aboriginal Business's silver-level Progressive Aboriginal Relations (PAR) certification. Certification occurs ever three years. In 2016, we introduced our STAR tracking program, which functions as a communication record-keeping and engagement measurement tool. This capacity fulfills 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 2018, to further support access to education TransAlta created an Indigenous Gap program with the Southern Alberta Institute of Technology (SAIT) to provide support to Indigenous students who need high school upgrading in order to enter a trade program.

In 2017, we supported an Indigenous Leadership Program at Banff Centre for Arts and Creativity. Approximately 250 Indigenous leaders from over 120 communities attended the leadership programs with help from TransAlta and other supporters.

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, Bears paw, 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**

Regardless of who our stakeholders are or who they represent, our goal is to act in the best interests of the Corporation and to create either financial, environmental or social value for both our stakeholders and TransAlta. 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 through the development of relationships and partnerships.

#### **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 150MW 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.

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 fulfills 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. For example, employees and other stakeholders may communicate with the Board, through the Audit and Risk Committee ("ARC"), by writing to the ARC; employees and other stakeholders may also communicate with the Board, through the ARC, by making submissions via the Corporation's toll-free telephone or online Ethic Helpline (see the Whistleblower System below for more details). Shareholders are also invited to communicate directly with the Board under the Corporation's Shareholder Engagement Policy, which outlines the Corporation's approach to proactive director-shareholder engagement at and in between the Corporation's annual shareholders meetings. Under the Shareholder Engagement Policy, shareholders can request meetings with members of the Board and can submit questions or inquiries to the Board, which the Corporation will respond to. A copy of the Shareholder Engagement Policy is available on our website at <https://www.transalta.com/about-us/governance/shareholder-engagement-policy/>. Shareholders and other stakeholders may, at their option, communicate with the Board on an anonymous basis. In addition, the Board has adopted an annual non-binding advisory vote on the Corporation's approach to executive compensation (say-on-pay). The Corporation is committed to ensuring continued good relations and communications with its shareholders and other stakeholders and regularly evaluates its practices in light of any new governance initiatives or developments in order to maintain sound corporate governance practices.

### Customers

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 cost 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 at <https://www.transalta.com/customers/>.

### 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 anti-competitive behaviour; disclosure on climate change management; third-party certifications on products; and demonstration of community investments. Furthermore, as we explore major projects, 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 through 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.

In addition, in early 2019, the Board of Directors adopted a Supplier Code of Conduct that applies to all vendors and suppliers of TransAlta. Under the Code, suppliers of goods and services to TransAlta are required to adhere to our core values, including as it pertains to health and safety, ethical business conduct and environmental leadership. The Code also allows suppliers to report ethical or legal concerns related to the Code via TransAlta's Ethics Helpline.

### 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, communities surrounding our plants will be impacted as our workforce will substantially decline. However, our proposed coal-to-gas conversions provide the opportunity to maintain some jobs at the power plants for substantially longer than would have been possible if the plants continued to only burn coal. 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 a smart and long-term energy transition in Alberta to minimize disruption and negative economic impact, and to provide support for facility redevelopment, funds for retraining and economic diversification in the province.

### Community Investments

During 2018, TransAlta contributed \$2.4 million in donations and sponsorships (2017 - \$2.6 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 \$1.1 million for the United Way.

In 2018, 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 seven 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 by closing the Centralia facility's two units, one in 2020 and the other in 2025. In order to invest the \$55 million, three funding boards were formed: The Weatherization Board (\$10 million), the Economic & Community Development Board (\$20 million) and the Energy Technology Board (\$25 million). To date, the Weatherization Board has invested \$5.9 million, the Economic & Community Development Board \$12 million and the Energy Technology Board \$3.9 million.

### Natural Capital

We continue to increase financial value from natural or environmental capital-related business activities, while reducing our carbon footprint. Comparable EBITDA from renewable energy generation in 2018 was \$322 million (2017 - \$289 million). Our revenue in 2018 from carbon-related offsets was \$21.6 million (2017 - \$27.7 million). In addition, in 2018 the sale of coal byproducts and waste-related recycling generated financial value in the range of \$25 million to \$35 million.

The following are key natural capital KPI trends:

Year ended Dec. 31	2018	2017	2016
Renewable energy comparable EBITDA	322.0	289.0	277.0
Carbon offsets revenue	21.6	27.7	29.0
GHG emissions (million tonnes CO <sub>2</sub> e)	20.8	29.9	30.7

### 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 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 a clean energy transition. We are planning the conversion of our Alberta coal units to natural gas in the 2020 to 2023 time frame.

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. Other material impacts that we manage and track performance on includes our environmental management systems, environmental incidents and spills, land use, water usage and waste management.

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

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 we therefore 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 policies in response to legal/regulatory and industry compliance or best practices.

Our performance on managing environmental impacts, reducing our environmental impact and capitalizing on environmental initiatives includes the following.

### Renewable Energy

Over the last 10 years, we have added approximately 1,200 MW in renewable energy capacity. Over 1,000 MW has been wind energy development and today we are positioned as an industry leader in wind energy. We continue to operate over 900 MW of hydro energy and our experience with hydro operations is over 100 years. In 2015 we made our first solar investment, 21 MW in Massachusetts, and we continue to look for opportunities to develop and operate solar energy. Our production from renewable energy in 2018 offset the equivalent of approximately 2.9 million tonnes of CO<sub>2</sub>e or the removal of approximately 620,000 cars from the roads in 2018.

### Carbon Offsets

In 2018, 200 MW of our Alberta wind capacity was eligible to generate offsets at a rate of \$30 tonne CO<sub>2</sub>e. Annual revenue generation from these offsets was in the range of \$10 million to \$15 million. In 2019, as per rules associated with the new *Alberta Carbon Competitiveness Incentive Regulation*, our offset eligibility capacity will expand to include additional capacity from our wind fleet and hydro fleet. As a result we anticipate offset revenue to rise to approximately \$25 million in 2019.

### Coal Transition

Our coal-to-gas conversion plan in Alberta is expected to vastly improve our environmental performance. Energy use, GHG emissions, 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, the majority of sulphur dioxide emissions ("SO<sub>2</sub>") and significantly reduce our nitrogen dioxide emissions ("NO<sub>x</sub>").

### Environmental Management Systems

All of our 73 facilities have Environmental Management Systems ("EMS") in place, the majority of which closely align with the internationally recognized ISO 14001 EMS standard. We have operated our facilities in line with ISO 14001 for 19 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 seven significant environmental incidents in 2018 (2017 - five incidents), which was below our target of nine. We categorize significant as violations or non-compliance to regulations or exceedance of limits in company operating approvals that resulted in or had the potential to result in enforcement action. This was another year of excellent performance that reflects our continuous improvement in tracking, reporting and identifying potential hazards. Five of our incidents occurred at our coal facilities and two incidents occurred at our gas facilities. None of these incidents resulted in a material environmental impact.

The following are the environmental incidents by fuel types:

Year ended Dec. 31	2018	2017	2016
Coal	5	5	13
Gas and renewables	2	—	3
<b>Total environmental incidents</b>	<b>7</b>	<b>5</b>	<b>16</b>

Incident types in 2018 were primarily regulatory in nature, whereby we had minor infringements on set regulatory requirements. These included two mercury exceedances at our Centralia coal facility, a nitrogen dioxide stack exceedance at our Sundance coal facility, failure to properly notify the regulator of un-salvaged topsoil, per EPEA Approval Condition 3.2.1, at our Sunhills mine, and a pH exceedance on an oil/water separator at our Sarnia gas facility. We also had two releases, one liquid and one gas. These included a secondary mine drainage water excursion from our Sunhills mine and a refrigerant release at our Ottawa gas facility. All incidents were managed in line with our EMS practice and resolved quickly. We

continue to target improvement and our corporate-wide 2019 target is five 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 2018 was 5 m<sup>3</sup> (2017 - 15 m<sup>3</sup>).

### Air Emissions

Air emissions in 2018 decreased significantly compared with 2017 levels. The reduction was due to a significant reduction in coal power generation from our Sundance coal facility and increased generation from co-firing with gas at our merchant facilities. SO<sub>2</sub> emissions decreased by 47 per cent, NO<sub>x</sub> emissions decreased by 37 per cent, particulate matter emissions decreased by 62 per cent and mercury emissions decreased by 41 per cent. These reductions highlight our commentary in our 2017 annual integrated report, which noted that we will dramatically reduce air emissions through our planned conversion of two coal units at Sundance, Alberta and the three coal units at Keephills, Alberta to gas-fired generation in the 2020 to 2023 time frame.

We continue to capture 80 per cent of mercury emissions at our coal plants and by 2025 our post-coal era, mercury emissions will be eliminated. Particulate matter and SO<sub>2</sub> emissions will also be virtually eliminated or considered negligible post-coal power generation. NO<sub>x</sub> emissions will also be reduced to levels under 20,000 tonnes annually.

We are well underway and remain on track to achieve our target of 95 per cent SO<sub>2</sub> emission reductions by 2030. Since 2005, we have reduced SO<sub>2</sub> emissions by 72 per cent. As noted above, we are on track to achieve our SO<sub>2</sub> target by 2025, well ahead of our 2030 goal. In 2018 we revised our NO<sub>x</sub> reduction target to 2030 from 95 per cent to 50 per cent. This allows flexibility as we convert coal facilities to natural gas and expand our natural gas fleet.

Year ended Dec. 31	2018	2017	2016
Sulphur dioxide (tonnes)	19,300	36,200	39,600
Nitrogen dioxide (tonnes)	28,000	44,400	48,400
Particulate matter (tonnes)	7,800	14,500	13,800
Mercury (kilograms)	70	110	130

### 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<sup>3</sup> of water across our fleet. In 2018 we withdrew 245 million m<sup>3</sup> and returned approximately 208 million m<sup>3</sup> 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<sup>3</sup>) over the last three years:

Year ended Dec. 31	2018	2017	2016
Water from environment	245	213	239
Water to environment	208	172	197
<b>Total water consumption</b>	<b>37</b>	<b>41</b>	<b>42</b>

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. In 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, the Whitewood mine in Alberta 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 2018, we reclaimed 28 acres (11 hectares) at our Highvale mine, which was below our target of 74 acres (30 hectares). This was due to weather conditions limiting the amount of final placement of topsoil. Topsoil placement is the final stage of reclamation. We reallocated resources to other stages of reclamation (such as ground leveling) to move us closer to final reclamation in following years, which keeps us on track with our long-range reclamation plan. The Centralia mine is no longer actively used for coal operations, but reclamation activity is ongoing. In 2018 we reclaimed 113 acres (46 hectares) of land. Since 1991, over 3,000 acres have been reclaimed and approximately 1.7 million seedlings have been planted as part of the reclamation work.

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

- 54 towers weighing over 9,000 kilograms ("kg");
- 61 nacelles, which is the housing of the turbine generating components, weighing 10,000 kg;
- 19 transformers weighing over 4,000 kg; and
- 32,000 litres of oil.

Our recycling efforts meant that we diverted close to 1,200,000 kg 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.

## Waste

In 2018 our operations generated approximately 1.3 million tonnes of waste. Waste volumes are all primarily non-hazardous. Only 0.1 per cent of waste volumes are hazardous materials. In 2018, only 0.1 per cent of waste was directed to landfill. From the remaining 99.9 per cent, 56 per cent was returned to the mine (ash from coal combustion), 43 per cent was reused and the remaining 0.3 per cent was recycled.

Our reuse waste or byproduct waste is resold in to markets. Byproduct sales and associated annual revenue generation typically ranges from \$25 million to \$35 million. Our operating teams are diligent at not only minimizing waste, but also maximizing 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.

## 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 declined by 30 per cent over 2017 as a result of coal retirements and reduced coal generation from our Sundance facility. Our coal-to-gas conversions will significantly reduce our energy usage as gas uses less energy for generation of a MWh.

Year ended Dec. 31	2018	2017	2016
Coal	309.8	447.4	469.1
Gas and renewables	48.6	49.4	59.2
Corporate	0.1	0.1	0.1
<b>Total energy use</b>	<b>358.5</b>	<b>496.9</b>	<b>528.4</b>

### **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 from the retirement 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 2016, which resulted in several weeks of flooding and threatened our coal deliveries. We focused on improving drainage infrastructure and using stockpiles to mitigate future risks.

### **Climate Change**

We believe in open and transparent reporting on climate change. Our climate change reporting is structured as per guidance from the Financial Stability Board's Task Force on Climate-Related Financial Disclosures ("TCFD") recommendations. The following highlights our management, performance and leadership of climate change related impacts. For more detailed information, please visit our Climate Change Management webpage: <https://www.transalta.com/sustainability/climate-change-management/>

#### *Governance*

The highest level of oversight on climate change related business impacts is at our Board level, specifically by our Governance Safety and Sustainability Committee ("GSSC") of the Board and the Audit and Risk Committee ("ARC") of the Board. Business impacts related to climate change are assessed by our executive team quarterly and reported to the Board GSSC and ARC, as applicable.

#### *Strategy*

Our corporate vision is to be a leading clean power company by 2025. To support this vision our strategic goals include growth in renewable energy and gas, while reducing a significant amount of emissions from our coal fleet by way of coal-to-gas conversions and coal retirements.

Our corporate goal is to reduce our GHG emissions by 19.7 million tonnes by 2030 compared to 2015 levels, while we grow renewable energy and gas. Our modeling shows that our target aligns us, under many scenarios, with science-based target setting, which highlights the resilience of our business to 2 degrees of global warming. We have not officially validated a science-based target, but continue to monitor and model our future performance with the Sectoral Decarbonization Approach from the Science Based Target Initiative.

Aligned with our corporate strategy, our business units or operations consistently seek energy-efficiency improvements, development of emissions offset portfolios to achieve emissions reductions at competitive costs, and development of clean combustion technologies.

We seek investment in climate change related mitigation solutions, such as renewable energy development, 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 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 one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. Production from renewable energy in 2018 resulted in avoidance of approximately 2.9 million tonnes of CO<sub>2</sub>e, which is equivalent to removing over 620,000 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.



### Risk Management

Risks and opportunities are identified at the business unit level and through corporate functions (government relations, regulatory, emissions trading and sustainability). Furthermore, risks and opportunities are monitored through our Corporation-wide risk management processes and actively managed on a priority basis. As noted above risks and opportunities are reviewed by our executive team quarterly and reported to the Board GSSC and ARC, as applicable.

The following highlights identified climate change risk or opportunities, which have been assessed and integrated into business operations.

Risk or opportunity	Management approach
<b>Policy requirements</b>	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 MOU 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
<b>Carbon pricing</b>	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.
<b>New technology</b>	We have demonstrated upside in growing renewables and gas-powered generation. From 2000 to 2018 we have grown renewables capacity from approximately 900 MW to over 2,200 MW. We have recently announced development of three wind projects, totaling over 330 MW of future capacity.
<b>Adaptation and mitigation</b>	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 towers 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.
<b>Water stress</b>	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.

### Greenhouse Gas Emissions

In 2018, we estimate that 20.8 million tonnes of GHGs with an intensity of 0.77 tonnes per MWh (2017-29.9 million tonnes of GHGs with an intensity of 0.86 tonnes per MWh) were emitted as a result of normal operating activities. Our significant reduction in GHG emissions is the result of coal closures and reduced coal power generation from our Sundance facility in Alberta and increased co-firing with gas at our merchant coal facilities. Notably, our 2018 emissions reductions, supported achieving our 2021 target to reduce GHG emissions by 30 per cent over 2015 levels of 32.2 million tonnes CO<sub>2</sub>e. This target was achieved well ahead of schedule and supports our clean power transition.

Our 2018 data are estimates based on best available data at the time of report production. GHGs include water vapour, CO<sub>2</sub>, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons and perfluorocarbons. The majority of our estimated GHG emissions are comprised of CO<sub>2</sub> 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* developed by the World Resources Institute and the World Business Council for Sustainable Development. 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.

The following are our GHG emissions in million tonnes CO<sub>2</sub>:

Year ended Dec. 31	2018	2017	2016
Coal	18.3	27.4	27.7
Gas and renewables	2.4	2.5	3.0
<b>Total GHG emissions</b>	<b>20.8</b>	<b>29.9</b>	<b>30.7</b>

Our total GHG emissions include both scope 1 and scope 2 emissions. 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. Scope 1 emissions in 2018 were estimated to be 20.6 million tonnes CO<sub>2</sub>e. Scope 2 emissions were estimated to be 0.2 million tonnes CO<sub>2</sub>e. We estimate our scope 3 emissions to be in the range of six million tonnes.

Future performance on GHG emissions will reduce as we retire or convert coal plants to gas and grow our renewable energy and gas fleet, while optimizing our existing fleet. Our target is to reduce 60 per cent or 19.7 million tonnes of GHG emissions by 2030 over 2015 levels, which is in line with UN Sustainable Development Goal ("SDG") Goal 13, Climate Action. Since 2015 we have reduced 9.1 million tonnes, which represents a reduction of 35 per cent.

The following highlights our longer-term track record on GHG emission reductions since 2005 and our projected emissions in 2030.

Year ended Dec. 31	2030	2018	2005
<b>Total GHG emissions</b>	<b>12.5</b>	<b>20.8</b>	<b>41.9</b>

In 2018, 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. In 2017 we were 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.

#### *Regional Regulation and Compliance*

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

Future changes to carbon regulations could 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 and other environmental 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*

On June 21, 2018, the *Greenhouse Gas Pollution Pricing Act* (GGPPA) was passed. Under this Act, the Canadian federal government implemented a national price on GHG emissions. The price will begin at \$20 per tonne of CO<sub>2</sub>e for emissions in 2019, rising by \$10 per year, until reaching \$50 per tonne in 2022.

On Jan. 1, 2019, the GGPPA's "backstop" mechanisms came into effect for large emitters in jurisdictions that did not have an independent carbon pricing program or where the existing program was not deemed equivalent to the federal system - Ontario, Manitoba, New Brunswick, Saskatchewan, Prince Edward Island, Yukon and Nunavut. The backstop mechanism has two components: a carbon levy for small emitters and regulation for large emitters called the Output-Based Pricing System (OBPS). The carbon levy sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources.

The OBPS is an intensity-based standard where large emitters must meet an industry specific emission intensity performance standard per unit of production. A large emitter's emission intensity per unit of product must meet their

industry's OBPS intensity performance standard. If the facility's emission intensity is below or above the performance standard, the facility will generate carbon credits or carbon obligations equal to the difference between the industry's emission intensity performance standard and the regulated facility's emission intensity.

#### Federal Gas Regulation

On Dec. 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. Under the regulation, new and significantly modified natural-gas-fired electricity facilities with a capacity greater than 150 MWs must meet a standard of 420 tCO<sub>2</sub>e per gigawatt hour (tCO<sub>2</sub>e/GWh) to operate. Units with a capacity of between 25 MW and 150 MW must meet a standard of 550 tCO<sub>2</sub>e/GWh.

The rules for converted units will allow the 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 are expected to provide 8 or 10 additional years of operating life to each of our units.

#### Federal Coal Regulation

On Dec. 18, 2018, amendments to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* came into force under the *Canadian Environmental Protection Act, 1999*. The amended regulations will require coal units to meet an emission level of 420 tCO<sub>2</sub>e/GWh by the earlier of end-of-life under the 2012 regulations or Dec. 31, 2029.

#### Alberta

On November 22, 2015, the Government of Alberta announced the Alberta Climate Leadership Plan. The government has now largely delivered on its commitments through legislation to require:

- the elimination of coal generation by 2030;
- the creation of the Renewable Energy Program (REP) to meet the commitment that renewables account for 30 per cent of Alberta's electricity system by 2030. Under the REP, the system operator, the AESO, is tasked with running procurement processes for government approved volumes of renewable power. To date, the AESO has run three separate Requests for Proposals (RFP). The RFPs have resulted in 20-year contracts for approximately 1,360 MWs of wind power projects. These projects are scheduled to be grid integrated between 2019 and 2021;
- the *Carbon Competitiveness Incentive Regulation* (CCIR) replaces the previous large emitters regulation, *Specified Gas Emitters Regulation* (SGER), moving from a facility-specific compliance standard to a product or sector performance compliance standard; and
- a carbon levy was introduced on most carbon emissions not covered by the CCIR.

On Jan. 1, 2018, the Alberta government transitioned from the SGER to the CCIR. Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sector performance compliance standard. Currently, the provincial government has announced that the carbon price will remain at \$30/tCO<sub>2</sub>e going forward and will not increase to the federally mandated price increase of \$40/tCO<sub>2</sub>e in 2021 and \$50/tCO<sub>2</sub>e in 2022; however, increases may be implemented by the federal government under their program equivalency review. The electricity sector performance standard was set at 370 tCO<sub>2</sub>e/GWh 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 renewables that did not receive credits under the previous standards will now be able to opt in to the CCIR and get carbon crediting up to the electricity sector performance standard in perpetuity. Once wind projects' crediting under SGER protocol ends, these projects will also be able to opt in to the CCIR system and be credited up to the performance standard for the rest of their operational life.

#### British Columbia

Beginning April 1, 2018, BC increased its carbon tax rate to \$35/tCO<sub>2</sub>e and committed to raise the price \$5 per year until it reaches \$50 per tonne in 2021.

BC Hydro has indicated there will be no additional contracts for independent power producer renewable projects with capacity above 15 MW. It has also suspended the purchase of energy from its Standing Offer Program for small projects up to 15 MW pending a review of the program.

#### Ontario

On Oct. 31, 2018, the Ontario government passed the *Cap and Trade Cancellation Act*. This Act removed all existing provincial carbon emission regulations and costs on large emitters.

The Canadian federal *Greenhouse Gas Pollution Pricing Act* requires provinces to have GHG gas regulations and prices in place that align with the federal GGPPA. On Oct. 23, the federal government announced that the federal program would be implemented in Ontario as of Jan. 1, 2019. Small emitters will face a carbon levy and large emitters, under covered industries, with annual GHG emission greater than 50,000 tCO<sub>2</sub>e will be subject to the OBPS. Ontario is now subject to the federal government's backstop carbon levy price for small emitters and the OBPS for large emitters.

On Nov. 29th, 2018, the Ontario government unveiled a new climate change policy called *Preserving and Protecting our Environment for Future Generations: A Made-In-Ontario Environment Plan*. The plan aims to keep the province working toward meeting the emissions-reduction goal of achieving 30 per cent reduction of 2005 levels by 2030. The plan commits to developing emission performance standards to achieve reductions from large emitters and references Saskatchewan's OBPS as an example. The government has indicated that it will be consulting and developing the program in 2019. The plan's specifics related to the electricity sector have not yet been defined and are expected to be determined through the program development process.

#### *Australia*

On Dec. 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The AUD 2.55 billion ERF is the centrepiece of the Australian government's policy and provides a policy framework to cut emissions by five per cent below 2000 levels by 2020 and 26 to 28 per cent below 2005 emissions by 2030.

The ERF's safeguard mechanism, commencing from July 1, 2016, is designed to ensure emissions reductions purchased by the Australian government through the ERF are not displaced by significant increases in emissions elsewhere in the economy. The ERF and its safeguard mechanism provide incentives to reduce emissions across the Australian economy.

The Australian government has also committed to develop a National Energy Productivity Plan with a target to improve Australia's energy productivity by 40 per cent between 2015 and 2030. The ERF is not expected to have a material impact on our Australian assets as a result of the Australian assets being primarily composed of gas-fired generation.

In addition, on June 23, 2015, the federal Australian government also reformed the Renewable Energy Target ("RET") scheme. The RET should add at least 33,000 gigawatt-hours (GWh) of renewable sources by 2020. This would double the amount of large-scale renewable energy being delivered compared to current levels and result in approximately 23.5 per cent of Australia's electricity generation being sourced from renewable projects.

#### *Pacific Northwest*

In 2010, the Washington Governor's office and Ecology negotiated agreements with TransAlta related to the operation of Centralia's two coal power electricity generating units. TransAlta agreed to retire its two Centralia coal units - one in 2020 and the other in 2025. This agreement is formally part of the state's climate change program. We currently believe that there will be no additional GHG regulatory burden on 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 of Washington.

## 2018 Sustainability Performance

### Stakeholder Communication and Value Creation

The information in this section 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.

### 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.

2018 Sustainability Targets			
	Financial	Results	Comments
<b>1. Maintain our investment grade rating</b>	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.
<b>2. Increase focus on FFO and EBITDA</b>	Deliver comparable EBITDA and FFO in the range of \$1,000 million to \$1,050 million and \$750 million to \$800 million, respectively <sup>(1)</sup>	Achieved	For the year ended Dec. 31, 2018, adjusted comparable EBITDA was \$988 million and adjusted FFO was \$770 million. Comparable EBITDA was adjusted to remove the impact of unrealized mark-to-market gains or losses. Additionally, Comparable EBITDA and FFO were adjusted to remove the \$157 million for the termination of Sundance B and C PPAs as this was not included in the targets.

*(1) Represents our revised outlook. As a result of strong performance in the first quarter of 2018, we revised the following 2018 targets: comparable EBITDA from the previously announced target range of \$950 million to \$1,050 million to \$1,000 to \$1,050 million, and FFO from the target range of \$725 million to \$800 million to \$750 million to \$800 million.*

	Human and Intellectual	Results	Comments
<b>3. Reduce safety incidents</b>	Achieve an Injury Frequency Rate below 0.53	Mostly Achieved	Although we narrowly missed our target, we achieved one of our lowest IFRs in our history. Our 2018 IFR was 0.54, a 25 per cent improvement over 2017 performance
	Achieve a Total Incident Frequency rate below 2.83	Achieved	Our 2018 TIF was 1.98, a 25 per cent improvement over 2017 performance
<b>4. Human resources</b>	Maintain voluntary turnover percentage under eight per cent	Not achieved	Our voluntary turnover in 2018 was 20 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
<b>5. Support employee development</b>	Continue development plans for all high-potential employees at the top three levels of the organization	Achieved	In 2018, we completed a six-month (peer-led) leadership training program, called Elevate, for our high-potential employees at the top three levels of the organization. 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
<b>6. Minimize fleet-wide environmental incidents</b>	Keep recorded incidents (including spills and air infractions) below 9	Achieved	We recorded seven significant environmental incidents in 2018, none of which had a material environmental impact. This was below our target of nine, but was a 40 per cent increase over 2017 performance
<b>7. Increase mine reclaimed acreage</b>	Replace annual topsoil rate at Highvale mine at a rate of 74 acres/year	Not achieved	Due to weather conditions, not all topsoil was placed to fully meet our target. Top Soil is the last stage of reclamation, despite weather constraints, we did manage to complete 28 acres. Instead, we reallocated resources to other stages of reclamation to move other areas closer to final reclamation (such as ground leveling). Overall we reduced reclamation spend by \$2.1 million and maintained progress towards our long-range reclamation plan
<b>9. Reduce air emissions</b>	Achieve a 95 per cent reduction from 2005 levels of TransAlta coal facility NOx and SO <sub>2</sub> emissions by 2030	On track	We are well underway and on track to achieve our target of 95 per cent emission reductions of SO <sub>2</sub> and NOx by 2030. Since 2005, we have reduced NOx emissions by 58 per cent and SO <sub>2</sub> emissions by 72 per cent. In 2018 we reduced approximately 16,000 tonnes of NOx emissions and 17,000 tonnes of SO <sub>2</sub> emissions over 2017 levels
<b>10. Reduce GHG emissions</b>	a) Our goal is to reduce our total GHG emissions in 2021 to 30 per cent below 2015 levels, in line with a commitment to the UN SDGs	Achieved	We achieved this target in 2018, well ahead of our target for 2021. In 2018 we reduced approximately 9.1 million tonnes of CO <sub>2</sub> e over 2017 levels due to reduced coal power generation from our Sundance facility and co-firing at our merchant coal facilities
	b) Our goal is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and to prevent two degrees Celsius of global warming	On track	We are well underway and on track to achieve our target of 60 per cent GHG emission reductions by 2030. Since 2015, we have reduced emissions by 36 per cent. In 2018 we reduced approximately 9.1 million tonnes of CO <sub>2</sub> e over 2017 levels

	Social and Relationship	Results	Comments
<b>11. Support quality education for youth</b>	Support equal access to all levels of education for youth and Indigenous peoples	Achieved	TransAlta provides an Aboriginal bursary to support education for Indigenous peoples that includes bursaries for both trades and post-secondary. TransAlta's criteria for accessing the bursary are open to any educational pursuit that will support the well being of Indigenous peoples and communities. The bursary is open to all Indigenous applicants that have completed high school. TransAlta has also created a Indigenous Gap program with SAIT to give support to Indigenous students where it is needed.
<i>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"</i>	Direct approximately \$0.75 million of community investment spending to youth education	Achieved	Our community investments have supported 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
<b>12. Increase internal best practice Aboriginal engagement awareness</b>	Develop sustainability and Indigenous engagement materials for integration within our developmental leadership programs at TransAlta	Achieved	An Indigenous Awareness presentation was developed, that 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
<b>13. TransAlta will be a leading clean power company by 2030</b>	By 2022, we will convert six coal plant units from coal-fired generation to gas-fired generation	On track	In 2018 we exercised our option to acquire a 50 per cent ownership in the Pioneer Pipeline connecting Tidewater's Brazeau River Complex to TransAlta's generating units at Sundance and Keephills. Our investment is subject to regulatory approval
<i>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"</i>	By 2025, 100 per cent of our owned asset company-wide net generation capacity will be from gas and renewables	On track	We continued our coal-to-gas transition plans in 2018, while announcing new renewable energy growth projects. Please see above and below for more detail.
	We will continue to seek new opportunities to grow our portfolio of 2,265 MW wind, hydro and solar assets	Achieved	In 2018 we announced development of three wind development projects, totaling over 320 MW of additional renewable energy capacity. Projects include a 90 MW wind facility in Pennsylvania (US), a 29 MW wind facility in New Hampshire (US) and a 207 MW wind facility in Alberta (Canada)
	Continue to explore viability of the Brazeau 900 MW pumped hydro expansion – doubling our hydro capacity in Alberta	Not achieved	In May 2018, the AESO released a report stating that dispatchable renewable resources are not needed in the Alberta market before 2030. The value and benefit of the Brazeau Hydro Pumped Storage project would be well beyond the 2030 period. The Corporation still believes that generation from pumped storage should be part of future calls for power under the Alberta <i>Renewable Electricity Program</i> . The Corporation is not spending additional development dollars on the project at this time, but will continue to work with governments to find the appropriate financial mechanisms for bringing low-cost, green, dispatchable renewables into the market to support low prices and emissions for Alberta customers



## 2019 Sustainable Development Targets

Our 2019 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
<b>1. Reduce safety incidents</b>	Achieve an Injury Frequency Rate below 0.43	20 per cent improvement over 2018 performance (0.54)
	Achieve a Total Incident Frequency Rate below 1.58	20 per cent improvement over 2018 performance (1.98)
		<b>Annual Performance Status</b>
<b>2. Minimize fleet-wide environmental incidents</b>	Keep recorded incidents (including spills and air infractions) below five	44 per cent improvement over 2018 target
<b>3. Increase mine reclaimed acreage</b>	Replace annual topsoil at Highvale mine at a rate of 110 acres/year	57 per cent increase over 2018 target (70 acres)
<b>4. Reduce air emissions</b>	Achieve a 95 per cent reduction from 2005 levels of TransAlta SO <sub>2</sub> emissions and 50 per cent reduction in NO <sub>x</sub> emissions by 2030	Revised NO <sub>x</sub> target to align with coal-to-gas conversion strategy and growth in gas estimations
<b>5. Reduce GHG emissions</b> Our GHG goal and targets support UN SDG Goal 13: Climate Action related to ensuring "integrate climate change measures into national policies, strategies and planning."	Our goal is to reduce our total GHG emissions in 2030 to 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and prevention of two degrees Celsius of global warming (our GHG and clean power targets assume reasonably anticipated growth and operating scenarios)	Consistent with 2018
		<b>Annual Performance Status</b>
	<b>Social and Relationship</b>	<b>Annual Performance Status</b>
<b>6. Support quality education for youth</b>	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	Consistent with 2018 target
Our education goal and target support UN SDG Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"		
		<b>Annual Performance Status</b>
	<b>Comprehensive</b>	<b>Annual Performance Status</b>
<b>7. TransAlta will be a leading clean power company by 2025</b>	Convert at least two coal units at Sundance, Alberta and three coal units at Keephills, Alberta to gas-fired generation in the 2020 to 2023 time frame	Revised 2018 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"	Aim that by 2025, 100 per cent of our owned net generation capacity will be from clean power (renewables and gas)	Consistent with 2018 target
	Seek new opportunities to grow our renewable portfolio of 2,265 MW wind, hydro and solar assets	Consistent with 2018 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 President and 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 robust 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,
- Supplier's 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, directors, consultants and suppliers with respect to, among other things, the protection and proper use of our assets. The codes also provide guidelines with respect to securing our assets, avoiding 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 and Directors' Code of Conduct each 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 and directors must comply.

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

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

In order to allow the Board to establish and manage the financial, environmental, and social elements of our governance practices, the Board has established the Audit and Risk Committee ("ARC"), the Governance, Safety and Sustainability Committee ("GSSC"), 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 consolidated 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 GSSC** 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 GSSC is also responsible for Board recruitment, succession planning and for the nomination of directors to the Board and its committees. In addition, the GSSC 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 GSSC also receives an annual report on the annual codes 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 GSSC 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 CEO, 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 and report on key risks quarterly. Specific Trading Risk Management reviews are held monthly by the Commodity and Compliance Risk Committee, and weekly by the Managing Director Commodity Risk, the commercial managing directors in Trading and Marketing, and the Senior Vice-President Trading and Marketing.

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

**The Commodity Risk & Compliance Committee** is chaired by our Senior Vice-President of Business Development and is comprised of the Chief Financial Officer, Chief Legal and Compliance Officer, Senior Vice-President of Business Development and Managing Director & Corporate Controller. 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 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) National 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 information 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, the ARC, senior management, and/or the Commodity Risk & Compliance Committee, as applicable. Reporting to this latter 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, contractors, shareholders or other stakeholders may confidentially or anonymously report any potential legal or ethical concerns, including concerns relating to accounting, internal control accounting, auditing or financial matters or relating to alleged violations of our codes of conduct. These concerns can be submitted confidentially and anonymously, either directly to the ARC or through TransAlta's toll-free telephone or online Ethics Helpline. The ARC Chair is immediately notified of any material complaints and, otherwise, the ARC receives a report at every quarterly committee meeting on all findings related to any material complaints or complaints relating to accounting or financial reporting or alleged breaches in internal controls over financial reporting.

### 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, 2018, associated with our proprietary commodity risk management activities was \$2 million (2017 - \$5 million). Refer to the Commodity Price Risk section of this MD&A for further discussion.

### Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other. For a further discussion of risk factors affecting the Corporation, readers are encouraged to read the Risk Factors section of our Annual Information Form for the year ended Dec. 31, 2018, available on our website at [www.transalta.com](http://www.transalta.com) and under our profile on SEDAR at [www.sedar.com](http://www.sedar.com) and on EDGAR at [www.edgar.gov](http://www.edgar.gov).

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 2018. 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 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 to mitigate 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	9

**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 2018, we had approximately 85 per cent (2017 - 92 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 cost 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 2018, 67 per cent (2017 - 57 per cent) of our cost of gas used in generating electricity was contractually fixed or passed through to our customers and 85 per cent (2017 - 83 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 US 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, and carefully matching the specifications mined with the requirements of our plants;
- co-firing natural gas with coal;
- 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 Climate Leadership Plan) and the US. We anticipate continued and growing scrutiny by investors and other stakeholders 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<sub>2</sub>, and NO<sub>x</sub>, 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 GSSC.

#### **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 or third-party credit insurance if a counterparty goes over its limits. Such security instruments can be collected if a counterparty fails to fulfil its obligation; 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, 2017. We had no material counterparty losses in 2018. 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, 2018:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables <sup>(1)</sup>	86	14	100	731
Long-term finance lease receivables	100	—	100	191
Risk management assets <sup>(1)</sup>	99	1	100	808
Loan receivable <sup>(2)</sup>	—	100	100	77
<b>Total</b>				<b>1,807</b>

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

(2) The counterparties have no external credit ratings.

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 \$13 million (2017 - \$40 million).

### Currency Rate Risk

We have exposure to various currencies as a result of our investments and operations in foreign jurisdictions, the earnings from those operations, the acquisition of equipment and services and foreign-denominated commodities from foreign suppliers, and our US-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 earnings or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

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

- hedging our net investments in 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 US exposure will be managed with a combination of interest expense on our US-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:

Factor	Increase or decrease	Approximate impact on net earnings
Exchange rate	\$ 0.04	\$27 million before tax

### 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, 2018, we have liquidity of \$1.0 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2019.

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, 2018, approximately 14 per cent (2017 - 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	15%	\$1 million before tax

### 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 Director 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;
- 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 before 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 2018, 50 per cent (2017 - 52 per cent) of our labour force was covered by 10 (2017 - 11) collective bargaining agreements. In 2018, four (2017 - four) agreements were renegotiated. We anticipate the successful negotiation of five collective agreements in 2019.

### 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 the new regulation to be formulated to give effect to the Alberta Climate Leadership Plan in 2020, 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 industry and government agency led 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 and regulatory agencies over the longer term.

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

### Transmission Risk

Access to transmission lines and transmission capacity for existing and new generation are key to 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 and transparent basis;
- applying innovative technologies to improve our operations, work environment and environmental footprint;
- 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, including the annual code of conduct sign-off.

### 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 and data used for the safe operation of our assets. In today's ever evolving cybersecurity landscape, any attacks or other breaches of network or information systems may cause disruptions to our business operations. Cyberattackers may use a range of techniques, from exploiting vulnerabilities within our user-base, to using sophisticated malicious code on a single or distributed basis to try to breach our network security controls. Attackers may also use a combination of techniques in their attempt to evade safeguards such as firewalls, intrusion prevention systems and antivirus software that exist on our network infrastructure systems. A successful cyberattack may allow for the unauthorized interception, destruction, use or dissemination of our information and may cause disruptions to our business operations.

We continuously 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. We have also established security awareness programs to help educate our users on cybersecurity risks and their responsibilities in helping protect 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 and data, there can be no assurance that these measures will be sufficient or that such security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner. We closely monitor both preventive and detective measures to manage these risks.

### General Economic Conditions

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

### Income Taxes

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

The Corporation is subject to changing laws, treaties and regulations in and between countries. Various tax proposals in the countries we operate in could result in changes to the basis on which deferred taxes are calculated or could result in

changes to income or non-income tax expense. There has recently been an increased focus on issues related to the taxation of multinational corporations. A change in tax laws, treaties or regulations, or in the interpretation thereof, could result in a materially higher income or non-income tax expense that could have a material adverse impact on the Corporation.

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

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

### Legal Contingencies

We are occasionally named as a party in various disputes, claims and legal or 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 dispute, claim or proceeding will be resolved in our favour or our liabilities with respect to such claims will not have a material adverse effect on us or our business, operations or financial results.

### 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 Dec. 31, 2018. 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. All insurance policies are subject to standard exclusions. Cyber coverage is not currently purchased.

## Fourth Quarter

### Consolidated Financial Highlights

Three months ended Dec. 31	2018	2017
Revenues	622	638
Net earnings (loss) attributable to common shareholders	(122)	(145)
Cash flow from operating activities	132	81
Comparable EBITDA <sup>(1)</sup>	233	275
FFO <sup>(1)</sup>	217	219
FCF <sup>(1)</sup>	98	101
Net earnings (loss) per share attributable to common shareholders, basic and diluted	(0.43)	(0.50)
FFO per share <sup>(1)</sup>	0.76	0.76
FCF per share <sup>(1)</sup>	0.34	0.35
Dividends declared per common share <sup>(2)</sup>	0.08	0.04
Dividends declared per preferred share <sup>(2)</sup>	0.52	0.26

<sup>(1)</sup> 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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.

<sup>(2)</sup> Dividends declared vary year over year due to timing of dividend declarations.

### Financial Highlights

We delivered consistent results in the fourth quarter with FCF of \$98 million, compared to \$101 million last year. FFO was \$217 million, which was comparable to the fourth quarter of 2017, as the business continues to deliver solid performance.

Net loss attributable to common shareholders in the fourth quarter of 2018 was \$122 million (\$0.43 net loss per share) compared to a net loss of \$145 million (\$0.50 net earnings per share) in the same period of 2017, an improvement of \$23 million compared to last year. This was driven by an income tax recovery of \$16 million compared to income tax expense of \$105 million in 2017, which was high due to the US tax rate reduction. This improvement was partially offset by lower comparable EBITDA of \$42 million and the write-off of project development costs of \$23 million in the fourth quarter of 2018.

### Segmented Cash Flows Generated by the Business and Operational Performance

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.

Segmented cash flows and operational performance for the business during the quarter is as follows:

<b>Three months ended Dec. 31</b>	<b>2018</b>	<b>2017</b>
Availability (%) <sup>(1)</sup>	91.5	88.4
Production (GWh) <sup>(1)</sup>	8,276	10,374
<b>Segmented cash inflow (outflow)<sup>(2)</sup></b>		
Canadian Coal	16	11
US Coal	21	15
Canadian Gas	59	56
Australian Gas <sup>(3)</sup>	35	33
Wind and Solar	74	73
Hydro	11	10
Generation cash inflow	216	198
Energy Marketing	10	15
Corporate	(34)	(28)
<b>Total comparable cash inflow</b>	<b>192</b>	<b>185</b>

*(1) Availability and production includes all generating assets under generation operations that we operate and finance leases and excludes hydro assets and equity investments. Production includes all generating assets, irrespective of investment vehicle and fuel type.*

*(2) This is not defined under IFRS. Presenting this item 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 Discussion of Consolidated Financial Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.*

*(3) 2017 cash flow revised to reflect the impacts of the change in the long-term receivable in Australian Gas.*

Adjusted availability for the three months ended Dec. 31, 2018, improved compared with the same period in 2017. Lower production for the three months ended Dec. 31, 2018, compared to the same period in 2017 is primarily due to the termination of the Sundance B and C PPAs and derates, partially offset by higher dispatch optimization in US Coal and higher Ancillary Services within our Hydro segment.

Cash flows generated by the business totalled \$192 million in the fourth quarter, an increase of \$7 million compared with last year's performance. Increased cash flows are largely due to the strong merchant prices in the Alberta market, lower sustaining capital spend and the settlement of a long-term receivable in Australian Gas, partially offset by higher carbon compliance costs.

## Discussion of Consolidated Financial Results

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, including the comparable figures below 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	2018	2017
Net earnings (loss) attributable to common shareholders	(122)	(145)
Net earnings attributable to non-controlling interests	43	19
Preferred share dividends	20	10
<b>Net earnings (loss)</b>	<b>(59)</b>	<b>(116)</b>
<i>Adjustments to reconcile net income to comparable EBITDA</i>		
Income tax expense	(16)	105
Gain on sale of assets and other	–	(1)
Foreign exchange (gain) loss	–	(6)
Net interest expense	50	57
Depreciation and amortization	152	180
<i>Comparable reclassifications</i>		
Decrease in finance lease receivables	15	15
Mine depreciation included in fuel cost	37	20
Australian interest income	1	1
Adjustments to earnings to arrive at comparable EBITDA		
Impacts associated with Mississauga recontracting <sup>(1)</sup>	30	20
Asset impairment charge (reversal)	23	–
<b>Comparable EBITDA</b>	<b>233</b>	<b>275</b>

(1) Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2018, are as follows: revenue \$30 million (2017 - \$29 million) and recovery related to renegotiated land lease of nil (2017 - \$9 million).

(2) Asset impairment charges for the three months ended Dec. 31, 2018, include a write-off of project development costs of \$23 million.

A summary of our comparable EBITDA by segments for the three months ended Dec. 31, 2018 and 2017 is as follows:

Three months ended Dec. 31	2018	2017
<b>Comparable EBITDA</b>		
Canadian Coal	56	66
US Coal	(1)	21
Canadian Gas	73	62
Australian Gas	32	29
Wind and Solar	72	78
Hydro	17	14
Energy Marketing	12	25
Corporate	(28)	(20)
<b>Total comparable EBITDA</b>	<b>233</b>	<b>275</b>

Comparable EBITDA decreased by \$42 million for the fourth quarter 2018, compared to 2017, primarily as a result of:

- Our Canadian Coal results were down \$10 million mainly due to higher carbon compliance costs in 2018.
- US Coal results were down \$22 million primarily due to unfavourable changes on unrealized mark-to-market positions.
- Our Canadian Gas business was up \$11 million period-over-period due to higher market price impacts.
- Australian Gas was up \$3 million and was fairly consistent with prior year results.
- Wind and Solar results were down \$6 million period-over-period mainly due to lower production, partially offset by higher prices in Alberta.
- Hydro results were \$3 million higher period-over-period due to higher Ancillary Service revenues.
- Energy Marketing's comparable EBITDA was down \$13 million during the fourth quarter of 2018 compared to 2017 mainly because the 2017 results were very strong in the Alberta market.
- Corporate costs increased by \$8 million in the fourth quarter mainly due to higher contractor costs.

### 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. FFO, FFO per share, FCF and FCF per share are non-IFRS measures, are not defined under IFRS, and therefore, should not be considered in isolation or as an alternative to or to be more meaningful than cash flow from operating activities as determined in accordance with IFRS, when assessing our financial performance or liquidity. See the Additional IFRS Measures and Non-IFRS Measures section above and elsewhere in this MD&A for further details. The table below reconciles our cash flow from operating activities to our FFO and FCF:

Three months ended Dec. 31	2018	2017
Cash flow from operating activities	132	81
Change in non-cash operating working capital balances	69	121
<b>Cash flow from operations before changes in working capital</b>	<b>201</b>	<b>202</b>
Adjustments		
Decrease in finance lease receivable	15	15
Other	1	2
<b>FFO</b>	<b>217</b>	<b>219</b>
Deduct:		
Sustaining capital	(56)	(62)
Productivity capital	(9)	(9)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(43)	(36)
Other	(1)	(1)
<b>FCF</b>	<b>98</b>	<b>101</b>
Weighted average number of common shares outstanding in the period	286	288
<b>FFO per share</b>	<b>0.76</b>	<b>0.76</b>
<b>FCF per share</b>	<b>0.34</b>	<b>0.35</b>

FFO was down \$2 million during the fourth quarter of 2018 compared to the same period in 2017. FCF decreased by \$3 million period-over-period as we continued to reduce our sustaining capital spend as a result of our decision to mothball certain Sundance units.

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

<b>Three months ended Dec. 31</b>	<b>2018</b>	<b>2017</b>
Comparable EBITDA	233	275
Provisions	—	(10)
Unrealized (gains) losses from risk management activities	27	(8)
Interest expense	(40)	(52)
Current income tax expense	(10)	(6)
Realized foreign exchange gain (loss)	1	8
Decommissioning and restoration costs settled	(8)	(7)
Other non-cash items	14	19
<b>FFO</b>	<b>217</b>	<b>219</b>
Deduct:		
Sustaining capital	(56)	(62)
Productivity capital	(9)	(9)
Dividends paid on preferred shares	(10)	(10)
Distributions paid to subsidiaries' non-controlling interests	(43)	(36)
Other	(1)	(1)
<b>Comparable FCF</b>	<b>98</b>	<b>101</b>
Weighted average number of common shares outstanding in the period	286	288
<b>Comparable FFO per share</b>	<b>0.76</b>	<b>0.76</b>
<b>Comparable FCF per share</b>	<b>0.34</b>	<b>0.35</b>



## 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 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	588	446	593	622
Comparable EBITDA	416	225	249	233
FFO	318	188	204	217
Net earnings (loss) attributable to common shareholders	65	(105)	(86)	(122)
Net earnings (loss) per share attributable to common shareholders, basic and diluted <sup>(1)</sup>	0.23	(0.36)	(0.30)	(0.43)
	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 earnings (loss) attributable to common shareholders	—	(18)	(27)	(145)
Net earnings (loss) per share attributable to common shareholders, basic and diluted <sup>(1)</sup>	—	(0.06)	(0.09)	(0.50)

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

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:

- effects of impairment charges during the second, third and fourth quarters of 2018 and second quarter of 2017;
- recognition of the \$157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018;
- a recovery of a writedown of deferred tax assets in the second quarter of 2017;
- change in income tax rates in the US in the fourth quarter of 2017;
- effects of non-comparable unrealized gains on intercompany financial instruments that are attributable only to the non-controlling interests in the first quarter of 2017;
- 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 is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P"). There have been no changes in our ICFR or DC&P during the year ended Dec. 31, 2018, that have materially affected, or are reasonably likely to materially affect, our ICFR or DC&P.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with IFRS. Management has used the *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) in order to assess the effectiveness of the Corporation's ICFR.

DC&P refer to controls and other procedures designed to ensure that information required to be disclosed in the reports we file or submit under securities legislation are recorded, processed, summarized and reported within the time frame specified in securities legislation. DC&P 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 securities legislation 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.

Together, the ICFR and DC&P frameworks provide internal control over financial reporting and disclosure. In designing and evaluating our ICFR and DC&P, 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 as such may not prevent or detect all misstatements, and management is required to apply its judgment in evaluating and implementing possible controls and procedures. Further, the effectiveness of ICFR is subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may change.

Management has evaluated, with the participation of our Chief Executive Officer and Chief Financial Officer, the effectiveness of our ICFR and DC&P as of the end of the period covered by this report. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2018, the end of the period covered by this report, our ICFR and DC&P were effective.