A Leader in Clean Electricity

TransAlta Corporation

2019 Annual Integrated Report

Letter to Shareholders

Clean Energy Investment Plan

On September 16, 2019, we held an investor day in Toronto where our team announced TransAlta's *Clean Energy Investment Plan*. We laid out a blueprint for achieving our vision of becoming a leader in clean electricity — committed to a sustainable future. Our plan includes a commitment to invest between $1.8 billion to $2.0 billion in growth and reinvestment from here to the end of 2023 and, more importantly, our plan is funded and in execution. And in 2019, we delivered strong performance, beating our expectations.

> **"We have a clear and simple plan that we advanced exceptionally well in 2019."**

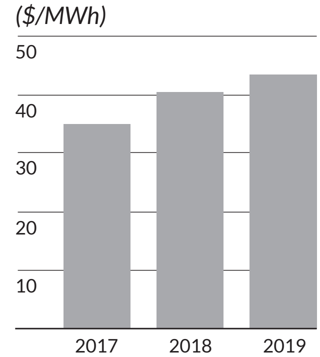
Today, we are on firm ground financially with a strategy that fits inside the overall energy decarbonization that we are witnessing globally. As countries move to set more stringent greenhouse gas regulations and commitments, and as consumers demand sustainability, we are positioned as a leader in renewable and clean natural gas generation. We believe that over the next ten years, electrification using clean natural gas, wind, water, solar and batteries will provide the opportunity to lower the carbon intensity of almost every good that is produced by our customers. We are experts in the forms of generation our customers demand and we can build them a plant or sell them a contract — in Alberta, across Canada, the US and Australia.

We have a clear and simple plan that we advanced exceptionally well in 2019. I am going to take you through some of the behind-the-scenes work that occurred throughout 2019 so that you can see why now, more than ever, is the time to invest in TransAlta.

Navigating 2019

One of our most important initiatives in 2019 was raising the cash we needed to make final decisions on converting our coal plants to gas. Having the Pioneer Pipeline commissioned early allowed us to significantly increase co-firing of our Alberta thermal units and accelerate our conversion plans. Plus, the forecast for $50/tonne carbon pricing by 2022 meant that every year that we stayed on coal was the potential for higher future carbon costs and much lower margins. If we stood still, our carbon bill would eventually climb to $405 million — an amount greater than our free cash flow! We had the pieces lined up to finalize our decisions, but we needed additional capital if we wanted to accelerate implementation and get ahead of the curve.

Gross Margin
($/MWh)



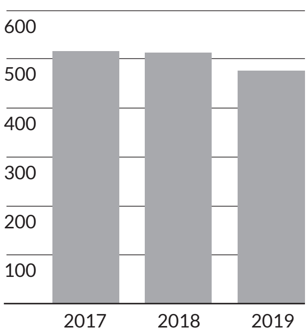
Raising capital at competitive rates in the markets was difficult. We felt our stock price was undervalued because investors were not yet convinced that we'd be able to move off coal and use gas — even with the Pioneer Pipeline in place — and early in 2019 they still didn't attribute enough value to our anticipated, higher future cash flows from our hydro assets once the PPA ended. We were also determined to repay our 2020 bonds and not raise additional corporate level debt. Our goal had been to finish 2020 with $1.2 billion in senior level corporate debt at the TransAlta level. We were determined to find an innovative way to raise cash that didn't result in a long-term debt burden.

We also engaged extensively with our larger shareholders in 2018 and Q1 2019, including Brookfield, and these discussions helped catalyze our desire to find a way to translate TransAlta's long-term potential into nearer-term value, accelerate our coal-to-gas strategy, return capital to shareholders, and crystalize the future, higher value of the hydro assets.

"We are rapidly building a natural gas-fired fleet that allows us to become Canada's leading clean electricity company."

We had been engaged in discussions with the Brookfield team for several years — including in both 2015 and 2017 concerning potential transactions — and trusted their integrity and business judgement. We saw them as the right strategic partner to construct an innovative deal that could bring all the pieces together. On March 25, we announced our strategic partnership and closed the transaction on May 1, after our annual general meeting, so that our shareholders could elect to ratify our approach through their support for the Board. The deal was financed against a percentage of our hydro assets at a 13 times future EBITDA(1) value — which crystallized the anticipated enhanced future value of our hydro assets. Further, we intentionally designed the debt to be convertible only after we had the anticipated higher cash flows from the hydro assets after they rolled off the PPA in 2020. We also used the opportunity to bring Brookfield in as a cornerstone partner, which meant that they would increase their equity ownership and offer us two very experienced and outstanding corporate directors. And we designed a performance incentive element. If our stock is trading over $17 by 2025, Brookfield can buy up to 49% of the hydro assets. This gives Brookfield the incentive to see all elements of our strategy advancing, including coal to gas — but also ensures we always retain a majority interest in the hydro assets.

Operating Maintenance and Administration *($M)*

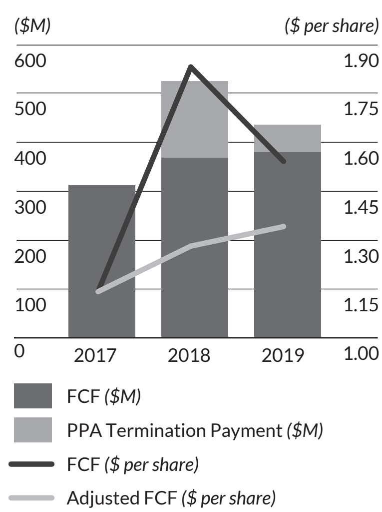


Having the cash early and an accelerated path off coal has proved to be the right decision. When the new Alberta government confirmed a carbon levy of $30 per tonne starting in 2020 for large emitters, our strategy was solidified. We believe that carbon pricing for large emitters in Canada is here to stay under all governments. We also believe that the odds are that over time, carbon will be priced more aggressively.

That is the back story to the decisions we made in 2019 that were presented at the September investor day conference. As of today, we will convert Sundance Unit 6 to gas by the end of 2020 and Keephills Units 2 and 3 in 2021. And we are also developing a re-powered combined cycle plant at Sundance Unit 5. As you can see, we are rapidly building a natural gas-fired fleet that allows us to become Canada's leading clean electricity company.

As we approached the end of the year, 2019 was coming together better than we expected from a free cash flow ("FCF") perspective. FCF is our key metric as it's the cash that is left after we pay all the bills and reinvest in sustaining capital. It's the cash that can pay down the principal on our debt, be returned to shareholders or be used for reinvestment. We also announced our updated dividend policy in September where we, in a highly disciplined way, tied future dividend increases to our deconsolidated funds from operations.

Free Cash Flow



(1) $10 million is deducted for capital expenditures.

An Outstanding Year for Business Performance

I am proud to say that the team at TransAlta delivered $379 million of Adjusted FCF, or $1.34 per share, representing almost a five per cent increase compared to 2018 and an 18 per cent increase to 2017 levels on a per share basis, excluding the additional $56 million of FCF that our legal team brought home through our successful arbitration against the Balancing Pool — an amount that few thought we could recover. All told, we delivered a total of $435 million of FCF or $1.54 per share.

> **"All told, we delivered a total of $435 million of FCF or $1.54 per share."**

Why did our year end so well when just a year before we had been concerned enough to guide the market to a potential downside of $270 million? Three reasons. First, our traders used their asset positions in transmission and their knowledge of real-time and day-ahead markets to take advantage of the volatility that now exists because of the high level of renewables in the system. They simply woke up every day and moved power to where it was needed — earning us an extra $50 million in cash that we had not anticipated. Second, commissioning the Pioneer Pipeline four months early allowed us to take advantage of low-priced summer gas in Alberta and blend gas into our boilers, significantly reducing our carbon emissions and costs. Finally, we were able to lower our costs at Sundance with the restructuring of our fleet and the 2018 mothball decisions. All told, we are proud of the cash flow performance coming out of the Canadian thermal fleet.

It is important to note that, while exceeding our original FCF expectations, we also operated without any injuries in our Wind, Hydro and Australia operations, and delivered a Total Injury Frequency ("TIF") across the entire fleet of only 1.12, an outstanding result compared to our TIF of 1.91 in 2018. Availability was also strong across our facilities, achieving 90 per cent availability fleet-wide.

Finally, 2019 is the culmination of the great work that our team has done to contain costs and build efficiencies through our Greenlight project.

> **"We also operated without any injuries in our Wind, Hydro and Australia operations, and delivered a Total Injury Frequency across the entire fleet of only 1.12."**

Continuing to Grow Our Renewables Business

Another key priority of ours that we announced in 2019 was to execute over $800 million of renewables and on-site construction projects. Both Antrim and Big Level, our new US wind projects, reached commercial operations in December 2019 and have commenced generating cash flow for 2020.

Project execution for Windrise, our wind project located in Alberta, commenced and we were excited to receive Alberta Utilities Commission ("AUC") approval ahead of schedule, providing further opportunities to optimize construction costs and integration. Windrise is targeting COD in 2021. Skookumchuck, a wind project in Washington State that we are pursuing, is progressing and we expect it to reach commercial operations by the end of June 2020.

We also have an extensive history of on-site generation that extends back to the early 1990s. Our experience and our team make us a strong partner in this segment. Building on this, we executed an agreement with SemCAMS Midstream to construct and operate a new cogeneration facility. Detailed construction activities have commenced and COD is targeted for 2021 as well.

Importantly, we received AUC approval for our WindCharger battery storage project, an innovative 10 MW/20 MWh energy storage project using lithium-ion batteries. The project, the first of its kind in Alberta, will store energy produced by our nearby Summerview II wind farm and discharge electricity onto the Alberta grid at times of high-peak demand — this is innovation in action.

We also have a team focused on building a pipeline of renewables and co-generation projects in the US. Demand for new wind in the US is expected to grow approximately 10 GW per year in the near term. As part of our plan, we acquired a portfolio from a US developer that now puts our own development pipeline at over 2,000 MW.

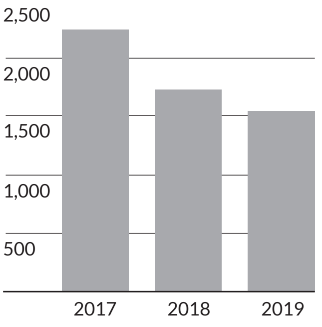
Strong Financial Position & Capital Allocation

A strong balance sheet underpins our plan and we have built off-ramps in the event that conditions change. Overall, we have tethered the investment strategy to maintaining a strong balance sheet and a dividend policy that allows investors to benefit as we move through our execution.

Above, I outlined the strategic reason to partner with Brookfield. The first-tranche proceeds of $350 million were received in May 2019 and allowed us to advance our coal-to-gas conversion strategy and return capital to shareholders. By the fourth quarter of 2020, we will receive the next tranche of the Brookfield proceeds to support our next phase of coal-to-gas conversions. This tremendous plan also allows us to achieve our goal of $1.2 billion of senior unsecured debt by the end of 2020.

The Brookfield investment has enabled us to accelerate our share buyback program allowing us to return capital more quickly to our equity shareholders. During the year, we returned $68 million of capital to shareholders through the NCIB program. We are making this investment as we believe that one of the best investments we can make is in our own strategy. We also raised our common dividend by a cent a share annually to reflect that we are now confident and ready to restore the idea of a growing dividend over time.

Net Recourse Debt, Exc. US Tax Equity Financing *($M)*



Our dividend policy is now also presented in our annual report, allowing investors to understand how the dividends received from our ownership of TransAlta Renewables are either being returned or reinvested for TransAlta shareholders.

We are confident that the above program balances the demands associated with reinvestment, new growth, debt repayments and, not the least of which, providing shareholders a return on and of their capital.

Continued Focus on Environmental, Social and Governance

The significance of environmental, social and governance ("ESG") has increased exponentially over the past few years, being driven in large part by investors that are spending more time understanding the sustainability of future cash flows. TransAlta has a long history of adopting leading sustainability practices, including 25 years of ESG reporting and voluntarily integrating sustainability reporting into our annual report since 2015. Three decades ago, in 1990, we were the first Canadian company to purchase carbon offsets, and in 2000 we were an early adopter of wind technology — and we are now one of the largest wind generators in Canada.

TransAlta continues to drive industry-leading ESG practices and I'm proud of the ambition represented in our 2020 ESG goals, including:

- minimizing environmental incidents and undertaking significant reclamation work;
- by 2030, achieving a 95 per cent reduction of SO_2 emissions and a 50 per cent reduction of NO_X emissions over 2005 levels from TransAlta's coal facilities;
- supporting equal access to all levels of education for youth and Indigenous peoples; and
- adopting a target of 50 per cent female membership on the Board by 2030 and achieving gender diversity of at least 40 per cent female employment by 2030.

"TransAlta continues to drive industry-leading ESG practices and I'm proud of the ambition represented in our 2020 ESG goals."

We are focused on ESG because it matters — and it makes good business sense. We will continue to lead the way as we have for 30 years.

Organizational Health

When we started our transformation journey in 2016, we focused on improving the organizational health of the Company. Organizational health for TransAlta is defined as "how we get work done together." It is not about morale and it is not narrowly defined as employee engagement. It's broadly about getting all our people in the boat rowing together. For TransAlta, it's also about nurturing innovation in every corner of the Company. We measure our performance on health against other organizations and use an external service provider to tabulate and analyze our results. In 2019, we made a significant jump in our health scores. We are now top decile across our Company in *front line innovation* — one of the key measures we wanted to improve. Watching our award winners at our President's Awards in early January talk about all the innovation we are undertaking across the fleet was a highlight for me. To improve our health while we are going through so much change was a testament to the unrelenting determination of our people to keep TransAlta competitive.

Changes in the Alberta Market

In 2019 we had a change in government in Alberta. The new government decided to stay with the existing energy-only market rather than move to a capacity market. Under a capacity market, we would have stuck more closely to converting our boilers to gas. Under an energy-only market, generating more output is more valuable, so having low-cost, efficient units as part of our fleet would increase returns to shareholders over time. In November, we strengthened this strategy by purchasing the gas turbines and related equipment from Kineticor. Overall, our portfolio and position in Alberta allow us to pivot and create value for shareholders. We know the energy-only market and have 20 years of experience in it as we move off the PPAs at the end of 2020.

So that was 2019 — an exciting step in our journey as we accelerate off coal.

Preparing for 2021 and Beyond

> **"As the PPAs roll off post-2020, we will be ready with a diverse competitive portfolio of electricity for Alberta customers."**

TransAlta's performance in 2019 is the culmination of the work undertaken to shift our strategy, cost structure and operating models to adapt to the new market and regulatory realities. We have made some great progress, but our work is not done yet. We are still fine-tuning the business with the right cost structure and business model to ensure we are competitive as we enter a fully deregulated market in Alberta as the remaining Coal and Hydro PPAs come to their completion.

Despite this change to our merchant risk profile, our diverse Alberta portfolio provides diversification to our cash flows from our Alberta business. As the PPAs roll off post-2020, we will realize market pricing, which will provide sufficient cash for returns to investors and for reinvestment in reliable supply.

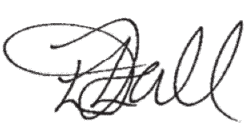
We are tracking ahead of our *Clean Energy Investment Plan*. As I highlighted at the beginning of this letter, we think TransAlta presents an excellent opportunity for an attractive investment. We have developed a sound reinvestment strategy in Alberta, which will continue to extend Alberta portfolio cash flows for a long time into the future.

I am spending my time in 2020 looking for ways to accelerate our strategy, studying new technologies for future investment, and working on policy at the provincial and federal levels. I believe that Canada is further ahead than any other OECD country on climate initiatives and it's time to stand up and be acknowledged for that. Canadians need to know our story and the story of how we can produce energy for the global energy markets more responsibly than almost anyone else. I have been working for 35 years on sustainability and I am an expert when it comes to who is acting and who is talking. We are a country of action.

To ensure I can do this work well, we appointed a COO, John Kousinioris, in the summer of 2019, to take on the day-to-day operational work and to continue driving our innovation. John, who was an excellent partner on the regulatory and policy side of our business, is a fast study on operations and, quite frankly, is an exceptional leader for our people. We also appointed Todd Stack to CFO. Todd is a 25-year TransAlta veteran who quickly earned the trust of the market and the Board. These appointments have given me and other members of the team the time to work on what's next.

Ambassador Gordon Giffin retires in April as Chair of our Board and I have to say that I will miss Gordon immensely. He has been our Chair since I started as CEO and his patience, guidance, determination and partnership got me through some bleak days. He spent countless hours helping the Board and the management team make the right strategy choices in the face of an early shut down of our coal fleet. I cannot close this letter without thanking him personally for all that he has done and how his contributions helped us achieve such an exceptional year in 2019.

On behalf of the leadership, we sincerely appreciate your support and we thank our employees for all that they do to ensure we are powering economies and communities sustainably and growing our Company along the way.



Dawn L. Farrell
President and Chief Executive Officer
March 3, 2020

Message from the Chair

Dear Fellow Shareholders,

I have had the great honour and privilege to serve as the Chair of the Board of Directors of TransAlta Corporation for the past nine years. To say that the last decade has been eventful for TransAlta would be an understatement. Our Company has faced significant economic and public policy headwinds for the past several years. Nevertheless, our team at TransAlta persisted. We have persevered and retained our relentless focus on driving our strategy of providing safe, low-cost, reliable and sustainable electricity to our customers while preserving and growing value for our shareholders.

It is with great satisfaction that I acknowledge 2019 as the turning point for this strategic execution. We can now begin to see the tangible results of the multi-year course that we mapped out in 2016 when the provincial and federal governments enacted punitive policy changes that fundamentally altered the economic future of our Alberta-based business. With the early operation of the Pioneer Pipeline, we have been able to co-fire coal units and thereby reduce costs and carbon. We have been able to take steps to achieve conversions of certain plants from coal to gas by issuing notices to proceed on boiler conversions, a process accelerated by the acquisition of the Kineticor generating assets. As designed three years ago, we are delivering on the plan to become a leading clean electricity company by 2025.

As I look back to 2011, we were proud to be Canada's largest publicly traded wholesale power producer and the country's largest producer of renewable power. Along with that came the unenviable position, however, of also being the largest emitter of CO_2 because of our coal-fired facilities. As I look forward into 2020 and beyond, I am proud to say we have quickly adjusted to changing views of coal and to dramatically altered public policy and are now on the path to becoming a leader in clean electricity — committed to a sustainable future. We are committed to a goal of reducing our total greenhouse gas emissions in 2030 to 60 per cent below our 2015 levels.

> **"We are committed to a goal of reducing our total greenhouse gas emissions in 2030 to 60 per cent below our 2015 levels."**

I want to thank our shareholders for once again being willing to participate in my outreach sessions. Your guidance in 2019 was particularly valuable. This past year we heard very clearly from our shareholders that you wanted a catalyst that would accelerate the long-term potential of our company into near-term value today. We heard you — and believe that the Brookfield strategic partnership did just that and more. It crystallized the future value of our Alberta Hydro PPA assets today, it delivered the capability to accelerate the execution of our coal-to-gas strategy, provided an early return of capital to our shareholders and added hydro operating expertise to the Company and renewables experience to our Board. The Brookfield investment also enabled us to commit to return up to $250 million to shareholders over a three-year period by way of our share buyback program. In 2019 alone, we returned $113 million to common shareholders through our share buybacks and common dividend.

We also committed to a capital allocation program providing investors with line-of-sight on how we would consider changes in the future and further transparency on how the dividends that we receive from our investment in TransAlta Renewables are being returned to shareholders or reinvested in TransAlta. The Board adopted a dividend policy of returning between 10% and 15% of TransAlta's deconsolidated Funds from Operations to common shareholders. At the same time, our capital allocation policy is tied to ensuring our deconsolidated debt levels at TransAlta remain within disciplined levels. It was a pleasure in January to start the process of raising the dividend again based on our confidence in the Clean Energy Investment Plan that the team announced to the market in September 2019.

We enhanced our Board in May 2019 with the addition of three new Directors who brought with them significant IPP and renewables experience. We were pleased to welcome Harry Goldgut, Richard Legault and Robert Flexon. They not only bring new perspectives and insight to the boardroom, but also have the skills and expertise needed to vet, pressure-test and drive our strategy of becoming a leading clean electricity company.

> **“We will continue to work diligently to identify and support talented female leaders.”**

We also extended our Board governance processes with the formation of our Investment Performance Committee. This newly established committee provides additional governance of management’s investment conclusions and execution of major capital expenditure projects in furtherance of the Company’s strategic plans. The Committee has been effective in assessing growth projects and reviewing and monitoring project management and control processes associated with allocating significant growth capital.

In January, the Board also approved significant ESG goals, including a diversity goal that our Board will be 50/50 male/female by 2030. We will continue to work diligently to identify and support talented female leaders. I am especially proud to be part of a Board that stepped out of the box to declare that it will have a team that reflects the gender balance of our population.

I am also proud to have worked alongside our dedicated Board and talented professionals at TransAlta during my tenure as Chair. I am confident that we have positioned the Company for a strong future of delivering value to our customers, our shareholders and our employees.

I would like to extend my best wishes to John Dielwart as he takes on the role of Chair and guides the final stages of our transformation and looks out to the future for the new opportunities that lie ahead.

These additions and changes, along with our talented incumbent Board, give us the breadth and depth to guide the strategy and set the Company up for its next hundred years.

On behalf of your Board, I can assure you that TransAlta remains dedicated to the responsible growth and development of this Company in the service of our customers and in the interest of our shareholders. As I transition the reins to my successor, I can also assure you that TransAlta’s future is on the right strategic path to deliver the clean electricity needs of the future.

> **“I am confident that we have positioned the Company for a strong future of delivering value to our customers, our shareholders and our employees.”**

Gordon D. Giffin

Ambassador Gordon D. Giffin
Chair of the Board of Directors
March 3, 2020

Management's Discussion and Analysis

Table of Contents

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our 2019 audited annual consolidated financial statements (the "consolidated financial statements") and our 2020 annual information form ("AIF"), each for the fiscal year ended Dec. 31, 2019. The 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, 2019. All dollar amounts in 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. All other dollar amounts in this MD&A are in Canadian dollars, unless otherwise noted. This MD&A is dated Mar. 3, 2020. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us" or the "Corporation"), including our AIF, is available on SEDAR at ***www.sedar.com****, on EDGAR at* ***www.sec.gov*** *and on our website at* ***www.transalta.com****. Information on or connected to our website is not incorporated by reference herein.*

Forward-Looking Statements

This MD&A 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: operating performance and transition to clean power generation, including our goal to have no generation from coal by the end of 2025; the Clean Energy Investment Plan and the benefits thereof; transitioning to 100 per cent clean electricity by 2025; the source of funding for the Clean Energy Investment Plan; our transformation, growth, capital allocation and debt reduction strategies; growth opportunities from 2020 to 2031 and beyond; potential for growth in renewables and on-site and cogeneration assets, including demand therefor and greenfield development acquisitions; the amount of capital allocated to new growth or development projects and funding thereof; our business, anticipated future financial performance and anticipated results, including our outlook and performance targets; our expectation that the $400 million second tranche of the investment by Brookfield Renewable Partners and its affiliates ("Brookfield") will close in October 2020; the benefit of the Brookfield Investment, including as it pertains to our expected success in executing on our growth projects, including expanding in the US renewable market and advancing our on-site and cogeneration business; 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 or repowering of our coal-fired units to natural gas, and the timing and costs thereof; expectations relating the benefits of the conversions and repowering; the terms of the current or any further proposed share buy back programs, including timing and number of shares to be repurchased pursuant to any normal course issuer bid and the acceptance thereof by the Toronto Stock Exchange ("TSX"); 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 that different energy sources will play in meeting future energy needs; expected financing of our capital expenditures; expected governmental regulatory regimes and legislation, 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; the mitigation of risks and effectiveness thereof, including as it pertains to climate change risk, environmental management, cybersecurity, commodity prices and fuel supply; 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, including the litigation with Fortescue Metals Group Ltd. relating to the South Hedland facility and the Mangrove (as defined below) proceedings relating to the Brookfield investment, each discussed further below; ability to achieve 2020 ESG (as defined below) targets; 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; Alberta spot power price being equal to $53 to $63 per megawatt hours ("MWh") in 2020; Mid-C spot power prices equal to US$25 to US $35 per MWh in 2020; sustaining capital in 2020 being between $170 million and $200 million; productivity capital of $10 million to $15 million; discount rates; our proportionate ownership of TransAlta Renewables Inc. ("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 or repowering; assumptions regarding the ability of the converted units to successfully compete in the Alberta energy 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 ("PPA") has expired; our being successful in defending against the claims alleged by Mangrove, discussed further below; the second $400 million tranche of the Brookfield investment closing as anticipated in October 2020; the Brookfield investment and its related arrangements with TransAlta having the expected benefits to the Corporation; and the higher adjusted EBITDA anticipated from our Alberta hydro assets subject to the Brookfield investment being realized.

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; changes to 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; disruptions in the source of fuels, including natural gas required for the conversions and repowering, as well as the extent of water, solar or wind resources required to operate our facilities; failure to meet financial expectations; natural and manmade disasters, including those resulting in dam or dyke failures; the threat of domestic terrorism and cyberattacks; pandemic or epidemics and any associated impact on supply chain; equipment failure and our ability to carry out or have completed the repairs in a cost-effective manner or timely manner or at all; 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; 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 facility and in relation to the Brookfield investment; 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 AIF for the year ended Dec. 31, 2019.

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.

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 8,385 MW[1] of capacity and use a broad range of generation fuels that include 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 electricity – committed to a sustainable future. We apply 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 safety, innovation, sustainability, integrity and respect, which together create a strong corporate culture that allows 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. We strive for a low to moderate risk profile over the long-term while balancing capital allocation and maintaining financial strength to allow for financial flexibility. Our segmented cash flow growth is driven by optimizing and diversifying our existing assets and further expanding our overall portfolio and presence in Canada, the United States of America ("US") and Australia. We are focusing on these geographic areas as our expertise, scale and diversified fuel mix create a competitive advantage that we can leverage to capture expansion opportunities in these core markets to create shareholder value.

Material Sustainability Impacts

Sustainability means ensuring that our financial returns consider short- and long-term economics, environmental impacts and societal and community needs. This MD&A integrates our financial and sustainability or Environment, Social and Governance ("ESG") reporting. Key elements of our sustainability disclosure are guided by our sustainability materiality assessment. To help inform discussion and provide context on how ESG affects our business, we have referenced the provincial securities commission guidance, Global Reporting Index, Sustainability Accounting Standards Board and the Task Force on Climate-related Financial Disclosures. Our content is structured following guidance on non-traditional capitals from the International Integrated Reporting Framework. In addition, we track the performance of 80 sustainability-related Key Performance Indicator ("KPIs") and have obtained a limited assurance report from Ernst & Young LLP over material KPIs.

(1) We measure capacity as net 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.

Corporate Strategy

Our strategic focus is to invest in a disciplined manner in a range of clean and renewable technologies such as wind, hydro, solar, battery and thermal (natural gas-fired and cogeneration) that produce electricity for industrial customers and communities to deliver returns to our shareholders.

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017. TransAlta is currently pursuing opportunities of $1.8 billion to $2.0 billion as part of this plan, including approximately $800 million of renewable energy projects either recently completed or already under construction. The implementation and execution of TransAlta's Clean Energy Investment Plan, including the acceleration of certain features of that plan, is in large part being facilitated by the $750 million strategic investment by Brookfield that we announced in March 2019 in response to feedback received from our shareholders during extensive engagement held in 2018 and 2019. The first $350 million tranche of Brookfield's investment closed in May 2019 and facilitated the acceleration of our coal-to-gas conversion plan discussed below. The second $400 million tranche of Brookfield's investment, anticipated to close in October 2020, will help further the advancement and implementation of the remainder of our Clean Energy Investment Plan, including our expected growth in renewables, while helping the Corporation maintain a strong balance sheet and financial flexibility to carry out the other pillars of our strategy discussed below. Refer to the Significant and Subsequent Events section of this MD&A for further details.

On Jan. 16, 2020, TransAlta announced near-term objectives that further support the Clean Energy Investment Plan. In addition, we announced our 2020 sustainability targets. For further details, refer to the 2020 Sustainable Development Targets section of this MD&A.

Our strategic priorities are focused on the following outcomes:

1. Successfully execute our coal-to-gas conversions

We are transitioning our Alberta thermal fleet to natural gas, as part of our Clean Energy Investment Plan. We plan to invest between $800 million to $1.0 billion to convert or repower our Alberta thermal fleet to natural gas. This will repurpose and reposition our fleet to a cleaner gas-fired fleet and advance our leadership position in onsite generation while generating attractive returns by leveraging the Corporation's existing infrastructure.

TransAlta's Clean Energy Investment Plan includes converting three of our existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. The cost to convert each unit is expected to be approximately $30 to $35 million per unit.

The Clean Energy Investment Plan also includes permitting to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined-cycle facility while achieving a similar heat rate. The Clean Energy Investment Plan assumes there are no delays in securing the natural gas supply requirements, which may result from regulatory or other constraints.

The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of our Alberta thermal assets; and
- Significantly reducing air emissions and costs.

The following key achievements over the past year helped us advance this part of our strategy:

On Dec. 17, 2018, the Corporation exercised our option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater Midstream and Infrastructure Ltd. ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. The investment for TransAlta, including associated infrastructure, was approximately $100 million.

In 2019, we issued Full Notice to Proceed ("FNTP") to convert Sundance Unit 6 and Keephills Unit 2 to natural gas by replacing the existing coal burners with natural gas burners. We are targeting to complete the conversion of Sundance Unit 6 by the second half of 2020 and Keephills Unit 2 by the first half of 2021.

We expect to issue Limited Notice to Proceed ("LNTP") for Keephills Unit 3 during the first half of 2020 and expect to complete the conversion of that unit during 2021. We are evaluating the potential to install dual fuel capability at Keephills Unit 3 to ensure we have optimal fuel flexibility as we transition the fleet from coal to gas, and to manage any timing delays in obtaining full gas requirements that may occur due to regulatory or other constraints.

We are currently seeking regulatory permits to repower the steam turbines at Sundance Unit 5 and Keephills Unit 1 by installing combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. Repowered units are expected to have a 40 per cent lower capital investment when compared to a new combined-cycle facility while achieving a similar heat rate.

To advance this repowering strategy, on Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F-class gas turbines and related equipment for $84 million. These turbines will be redeployed to our Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. We expect to issue LNTP in 2020 and FNTP in 2021 for Sundance Unit 5, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined-cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million, well below a greenfield combined-cycle project. In conjunction with the Sundance Unit 5 permitting, we are also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined-cycle unit, depending on market fundamentals. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of greenhouse gas ("GHG") costs, starting in late 2023 with Shell Energy North America (Canada).

2. Deliver growth in our renewables fleet

We are further expanding our renewables platform. We currently have over $400 million of renewable energy construction projects to be completed in 2020 and 2021. We completed and commissioned two wind farms in 2019 investing over $340 million through TransAlta Renewables. Our focus is to ensure that we solidify returns through exceptional project execution and integration where we are able to commission and operate assets within our schedule and cost objectives.

The following key achievements in 2019 helped us advance this part of our strategy:

US Wind Projects

In 2019, we completed the construction of two wind projects (collectively, the "US Wind Projects") in the Northeastern US. The Big Level wind project ("Big Level") acquired on Mar. 1, 2018, consists of a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. The Antrim wind project ("Antrim") acquired on Mar. 28, 2019 consists of a 29 MW project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. Big Level and Antrim began commercial operations on Dec. 19, 2019, and Dec. 24, 2019, respectively. The US Wind Projects have added an additional 119 MW of generating capacity to our Wind and Solar portfolio.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs.

Windrise Wind Project

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the Alberta Electric System Operator ("AESO") as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO executed a Renewable Electricity Support Agreement with a 20-year term. The Windrise wind project is situated on 11,000 acres of land located in the county of Willow Creek, Alberta, and is expected to cost approximately $270 million to $285 million. The project development work is on schedule. Windrise has secured approval for the facility from the Alberta Utilities Commission ("AUC") and is currently permitting transmission lines required to connect the facility to the Alberta grid. Construction activities will start in the second quarter of 2020 and the project is on track to reach commercial operation during the first half of 2021.

Skookumchuck Wind Project
On Apr. 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind project, a 136.8 MW wind project currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy. TransAlta has the option to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be approximately $150 million to $160 million, a portion of which is expected to be funded with tax equity financing.

WindCharger Project
During the first quarter of 2019, TransAlta approved the WindCharger project, an innovative energy storage project, which will have a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. WindCharger is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview Wind Farm Substation. WindCharger will store energy produced by the nearby Summerview II Wind Farm and discharge into the Alberta electricity grid at times of peak demand. This project is expected to be the first utility-scale battery storage facility in Alberta and will be receiving co-funding support from Emissions Reduction Alberta. Regulatory applications, including a facilities application to the AUC and an interconnection application to the AESO, were submitted in 2019. AUC approval was granted in November 2019 and the AESO approval is expected by the end of the first quarter of 2020. Detailed engineering designs, as well as the procurement of long-lead equipment, has been completed. Construction is on track to begin in March 2020 with a commercial operation date expected within the second quarter of 2020. The total expected cost of the project to TransAlta is $7 million to $8 million.

3. Expand presence in the US renewables market
We are focusing our business development efforts in the renewables segment of the US market. Demand for new renewables in the US is expected to grow in the near term. We currently have 2,000 MW at different stages in our development pipeline. These opportunities are expected to grow TransAlta Renewables, utilize its excess debt capacity and deliver stable dividends back to TransAlta.

In addition to the US Wind Projects and the Skookumchuk wind project discussed above, during 2019, TransAlta acquired a portfolio of wind development projects in the US. If we decide to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025. If a decision is made to not move forward with a project or the costs are no longer considered to be recoverable, the costs are charged to earnings. Estimated returns on these projects and similar projects are sufficient to recover costs of unsuccessful development projects.

4. Advance and expand our on-site generation and cogeneration business
We will grow our on-site and cogeneration asset base, a business segment we have deep experience in, having provided on-site cogeneration services to various customers since the early 1990s. Our current pipeline under evaluation is approximately 900 MW and our technical design, operations experience and safety culture make us a strong partner in this segment. We see this segment growing as industrial and large-scale customers are looking to find solutions to help lower costs of power production, replace aging or inefficient equipment, reduce network costs and meet their ESG objectives.

Consistent with this strategy, on Oct. 1, 2019, TransAlta and SemCAMS announced that they entered into definitive agreements to develop, construct and operate a cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

The highly efficient cogeneration facility will have an installed capacity of 40 MW. All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights. The development of the cogeneration facility at Kaybob South No. 3 is expected to eliminate the need for traditional boilers and reduce annual carbon emissions of the operation by approximately 100,000 tonnes carbon dioxide equivalent ("CO_2e"), which is equivalent to removing 20,000 vehicles off Alberta roads.

5. Maintain a strong financial position

We intend to remain disciplined in our capital investment strategy and continue to build on our already strong financial position.

We currently have access to $1.7 billion in liquidity, including $411 million in cash. During 2019, we entered into transactions to strengthen our position to execute on the Clean Energy Investment Plan including: (i) entering into an investment agreement with Brookfield providing us with $750 million in strategic financing, (ii) increasing our credit facilities by $200 million to a total of $2.2 billion and extending the maturity of the term by one year, and (iii) successfully obtaining US$126 million of tax equity financing associated with the US Wind Projects.

To further this strategy in 2020, we will repay the $400 million bond maturing in November 2020 and continue our share buyback program in an amount up to $80 million.

The Clean Energy Investment Plan will be funded from the cash raised through the strategic investment by Brookfield, cash generated from operations and raising capital through TransAlta Renewables. For further details on the Brookfield investment, refer to the Significant and Subsequent Events section of this MD&A.

In addition, we continue to execute on our multi-year Greenlight program that is focused on transforming our business and delivering TransAlta's strategy by reducing our cost structure. The program is entering its fourth year since implementation, and with each passing year it creates a continuous improvement culture that improves the way employees work together to deliver better business results. The program is focused on creating a structure around our people that enables them to identify, develop and deliver projects that improve performance across the Corporation with an emphasis on delivering sustainable value and cash flow improvements. Through the program, we have instituted ways to optimize our assets, minimize GHG emissions, reduce capital and operating costs, improve fuel usage and streamline processes. As this approach is increasingly embedded into the Corporation it has increased the empowerment of our employees, strengthened our processes and improved our corporate culture while reducing our operating costs.

Growth and coal-to-gas conversion expenditures

Our growth projects are focused on sustaining our current operations and supporting our growth strategy in our Clean Energy Investment Plan. A summary of the significant growth and major projects that are in progress is outlined below:

	Total project				
	Estimated spend	Spent to date[1]	Estimated spend in 2020	Target completion date	Details
Project					
Big Level wind development project[2]	225 - 240	234	4	Commissioned	90 MW wind project with a 15-year PPA
Antrim wind development project[3]	100 - 110	106	—	Commissioned	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	95 - 100	100	—	Commissioned	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Skookumchuck wind development project[4,5]	150 - 160	—	80	Q2 2020	Option to purchase a 49 per cent ownership in the 136.8 MW wind project with a 20-year PPA
Windrise wind development project[5]	270 - 285	49	233	Q2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery[5,6]	7 - 8	1	6	Q2 2020	10 MW/20 MWh utility-scale storage project
Boiler conversions	100 - 200	28	69	2020 to 2022	Coal-to-gas conversions at Canadian Coal
Repowering	750 - 770	85	20	2023	Repower the steam turbines at Sundance Unit 5
Kaybob cogeneration project[5]	105 - 115	17	59	Q4 2021	40 MW cogeneration project with SemCAMS under a 13-year fixed price contract
Total	**1,802 - 1,988**	**620**	**471**		

(1) Represents cumulative amounts spent as of Dec. 31, 2019.
(2) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is approximately US$173 million to US$185 million, spent to date is US$179 million and estimated remaining spend in 2020 is US$3 million. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(3) The numbers reflected above are in CAD but the actual cash spend on this project is in US funds and therefore these amounts will fluctuate with changes in foreign exchange rates. The estimated total spend is approximately US$77 million to US$85 million, spent to date is US$80 million and estimated remaining spend in 2020 is nil. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(4) The estimated spend in 2020 assumes the project will receive tax equity financing for the remainder of the total project spend.
(5) These projects will potentially be dropped down to TransAlta Renewables.
(6) Net of expected government reimbursements.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2019	2018	2017
Revenues	**2,347**	2,249	2,307
Fuel, carbon compliance and purchased power	**1,086**	1,100	1,016
Operations, maintenance and administration	**475**	515	517
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Cash flow from operating activities	**849**	820	626
Comparable EBITDA(1,2,3)	**984**	1,161	1,030
Funds from operations(1,3)	**757**	927	804
Free cash flow(1,3)	**435**	524	328
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.86)	(0.66)
Funds from operations per share(1,3)	**2.67**	3.23	2.79
Free cash flow per share(1,3)	**1.54**	1.83	1.14
Dividends declared per common share	**0.12**	0.20	0.12
Dividends declared per preferred share(4)	**0.78**	1.29	0.77

As at Dec. 31	2019	2018	2017
Total assets	**9,508**	9,428	10,304
Total consolidated net debt(1,5)	**3,110**	3,141	3,363
Total long-term liabilities(6)	**4,329**	4,414	4,311

(1) These items are not defined and have no standardized meaning 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. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.
(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and the remaining $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019 ("PPA Termination Payments"). See the Significant and Subsequent Events section for further details.
(4) 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.
(5) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease obligations, net of available cash and cash equivalents, the principal portion of restricted cash on TransAlta OCP and the fair value of economic hedging instruments on debt. See the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.
(6) Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

At the end of 2018, we had a number of contracts expire, which impacted our comparable EBITDA. Through our strong performance in 2019, we recovered a significant amount of these expected declines through innovation, cost reductions and higher revenue from our Energy Marketing segment.

Revenues in 2019 were $2,347 million, up $98 million compared to 2018, mainly as a result of strong revenue generated from our Energy Marketing segment as well as higher production, resulting in higher revenue, within the US Coal segment due to the strong merchant pricing in the Pacific Northwest.

Comparable EBITDA decreased by $177 million compared to 2018. After adjusting for the PPA Termination Payments in 2019 and 2018, comparable EBITDA decreased by $76 million for the year ended Dec. 31, 2019, compared to 2018. This decrease was expected as a result of the expiry of the Mississauga contract and lower scheduled payments on the Poplar Creek contract. Strong performance at the Canadian Coal and Energy Marketing segments as well as lower Corporate costs have significantly offset this expected decrease. Comparable EBITDA for the year ended Dec. 31, 2019, was negatively impacted by the unplanned outage at US Coal during the first quarter of 2019.

At Canadian Coal, comparable EBITDA improved in 2019 due to the combined impact of higher realized prices as a result of greater merchant production, increased co-firing resulting in lower fuel, carbon compliance and purchased power costs, as well as lower operations, maintenance and administration ("OM&A") costs. In addition, performance from our Energy Marketing segment was stronger than 2018, particularly from US Western and Eastern markets due to continued high levels of volatility across North American power markets.

Free cash flow ("FCF"), one of the Corporation's key financial metrics, totalled $435 million, down $89 million compared to last year. FCF, after adjusting for the PPA Termination Payments, increased $12 million compared to last year, primarily as a result of lower sustaining and productivity capital expenditures and lower distributions paid to subsidiaries' non-controlling interests. Significant changes in segmented cash flows are highlighted in the Segmented Comparable Results within this MD&A.

OM&A expense for the year-ended Dec. 31, 2019, decreased by $40 million compared to 2018. This decline in OM&A is largely due to lower costs in our Canadian Coal and Corporate segments and ongoing streamlining of our workforce. Lower salary, contractor and materials expenses were partially offset by higher legal fees.

Fuel, carbon compliance and purchased power costs were lower in 2019 compared to 2018. This decrease was mainly due to our increased gas supply available for co-firing, as a result of the Corporation transporting natural gas on the Pioneer Pipeline earlier than expected. Co-firing, when economical, allows us to produce fewer GHG emissions than coal combustion, which lowers our GHG compliance costs.

Net earnings attributable to common shareholders for the year ended Dec. 31, 2019, were $52 million, compared to a loss of $248 million in the prior year. Increased earnings were partially driven by the Keephills 3 and Genesee 3 swap with Capital Power Corporation that closed in the fourth quarter of 2019, where we recognized a gain on termination of the coal rights contract of $88 million and a gain on the sale of Genesee 3 of $77 million, in addition to the $56 million PPA Termination Payments received during the third quarter of 2019. Excluding the PPA Termination Payments and impairment charges in both years, as well as the gains related to Keephills 3 and Genesee 3 in 2019, we have a net loss of $20 million in 2019 compared to a net loss of $174 million in 2018. Stronger earnings are attributable to stronger performance at Canadian Coal and Energy Marketing, strong Alberta pricing, the Alberta tax rate reduction, lower OM&A costs and lower interest expense, partially offset by other losses on sale of property, plant and equipment ("PP&E").

Ability to Deliver Financial Results

The metrics we use to track our performance are comparable earnings before interest, taxes, depreciation and amortization ("comparable EBITDA"), funds from operations ("FFO") and FCF. The overall performance of our portfolio was in line with our 2019 outlook. The Corporation is within the upper end of the revised FCF target of $350 million to $380 million, excluding the impact of the PPA Termination Payments. Reported FCF benefited from the receipt of $56 million from the Balancing Pool on settlement of the termination of the Sundance B and C PPA dispute.

The following table compares target to actual amounts for each of the three past fiscal years:

Year ended Dec. 31		2019	2018	2017
Comparable EBITDA	Target(1)	**875-975**	1,000-1,050	1,025-1,100
	Actual(2)	**984**	1,161	1,030
	Adjusted Actual(3)	**928**	1,004	996
FCF	Target(1)	**350-380**	300-350	270-310
	Actual	**435**	524	328
	Adjusted Actual(3)	**379**	367	311

(1) Represents our revised outlook. Due to strong results from our Canadian Coal segment, in the fourth quarter of 2019, we revised our FCF target from a range of $270 million to $330 million to a range of $350 million to $380 million. 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, 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, FCF target range from $300 million to $365 million to the target range of $270 million to $310 million.

(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

(3) 2019 and 2018 were adjusted for the PPA Termination Payments as these were not included in the targets. 2017 amounts were adjusted to remove the impact related to the Ontario Electricity Financial Corporation ("OEFC") indexation dispute: Comparable EBITDA was reduced by $34 million and FCF was reduced by $17 million.

Significant and Subsequent Events

Investor Day

On Sept. 16, 2019, TransAlta held our 2019 Investor Day, and announced our Clean Energy Investment Plan. See the Corporate Strategy section of this MD&A for additional 2019 significant events to advance our Clean Energy Investment Plan.

In addition, the Corporation announced that it adopted, based on TransAlta level deconsolidated cash flows, a deconsolidated Debt/EBITDA target of 2.5 to 3.0 times, and a dividend policy of returning between 10 and 15 per cent of TransAlta deconsolidated FFO to common shareholders. The credit metrics and dividend policy are being presented on a deconsolidated basis, allowing investors to understand how the dividends received from TransAlta Renewables and TransAlta Cogeneration L.P. ("TA Cogen") are either being returned or invested for TransAlta shareholders. See the Key Financial Ratios section of this MD&A for further details.

On Jan. 16, 2020, the Board declared a quarterly dividend of $0.0425 per common share payable on Apr. 1, 2020, to shareholders of record at the close of business on Mar. 2, 2020, which represents a 6.25 per cent increase in our dividend level.

Strategic Investment by Brookfield

Following extensive engagement by the Corporation with several of its shareholders, on Mar. 25, 2019, the Corporation announced it entered into an agreement (the "Investment Agreement") whereby Brookfield agreed to invest $750 million (the "Investment") in the Corporation. The Investment provides the financial flexibility to drive TransAlta's transition to 100 per cent clean electricity by 2025, recognizes the anticipated future value of TransAlta's Alberta Hydro Assets and accelerates the Corporation's plan to return capital to its shareholders. As discussed in the Corporate Strategy section of this MD&A, the Brookfield Investment was key to the implementation and advancement of the Corporation's Clean Energy Investment Plan, including facilitating or accelerating several key pillars of the Corporations' strategic plan.

Under the terms of the Investment Agreement, Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs were recognized as part of the carrying value of the unsecured subordinated debentures issued at that time.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share. In connection with the Investment, Brookfield nominated and TransAlta shareholders elected two experienced officers of Brookfield, Harry Goldgut and Richard Legault, to our Board of Directors at the 2019 Annual and Special Meeting of shareholders. TransAlta and Brookfield intend to work together to complete TransAlta's transition to clean electricity, maximize the value of the Alberta Hydro Assets and create long-term shareholder value.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation and maximizing the value of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the OM&A expense on the statement of earnings (loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment (which occurred on May 1, 2019).

Additional details about the Investment can be found in our material change report dated Mar. 26, 2019, available electronically on SEDAR at www.sedar.com and on EDGAR at www.sec.gov as well as in our AIF. Copies of the Investment Agreement, together with copies of the exchangeable debenture issued to Brookfield on May 1, 2019, the registration rights agreement entered into with Brookfield in respect of common shares held in TransAlta, and the exchange and option agreement with Brookfield governing the terms of the exchange of the exchangeable securities issued under the Investment, are also available on SEDAR and on EDGAR. Shareholders are urged to read these documents in their entirety.

On Apr. 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020. See the Other Consolidated Analysis section of this MD&A for additional information on the Mangrove proceedings.

Normal Course Issuer Bid

On May 27, 2019, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement a Normal Course Issuer Bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may purchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 May 29, 2019, and ends on May 28, 2020, 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, no more than 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended Apr. 30, 2019) 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, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million.

Termination of the Alberta Sundance PPAs with the Balancing Pool

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective Mar. 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective Mar. 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on Mar. 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation which the Corporation pursued from the Balancing Pool through an arbitration initiated under the PPAs. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full additional amount it was seeking to recover, being $56 million, plus GST and interest.

TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the Genesee 3 facility for Capital Power's 50 per cent ownership interest in the Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The Keephills 3 facility is a 463 MW coal-fired generating facility located approximately 70 kilometres west of Edmonton, Alberta, adjacent to TransAlta's existing Keephills Unit 1 and Unit 2 power plants. The Keephills 3 facility achieved commercial operation in 2011 and has been identified as a candidate for TransAlta's intended coal-to-gas conversions.

The transaction price for each non-operating interest largely offset each other, resulting in a payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

The Corporation early-adopted amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test, that the Corporation elected to apply to its acquisition of the non-operating interest in Keephills 3. As a result, on the transaction closing of Oct. 1, 2019, the acquisition has been accounted for as an asset acquisition and the transaction price was allocated based on the relative fair values of those assets and liabilities as at the date of the acquisition. The transaction price of $301 million was allocated as follows: working capital of $11 million, PP&E of $308 million, other assets of $3 million, less other liabilities of $2 million and decommissioning and other provisions of $19 million. The net increase to our PP&E balance relating to Keephills 3 and Genesee 3 swap, including the impact of shortening the useful lives of the coal assets at Keephills 3, is estimated to increase depreciation expense in 2020 by approximately $72 million.

As a result of the sale of our interest in Genesee 3, we recognized a gain on sale of approximately $77 million in the fourth quarter.

On closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. The Sunhills mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. Upon termination of this agreement in the fourth quarter of 2019, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings.

Board of Director Changes

On Jan. 16, 2020, we announced that the Board has appointed John P. Dielwart as Chair of the Board, upon his re-election as an independent director at TransAlta's next annual shareholder meeting and immediately following Ambassador Gordon Giffin's retirement from the Board. As previously announced, Ambassador Giffin is retiring from the Board in 2020 after serving as Chair since 2011.

Mr. Dielwart has served as an independent director on the Board since 2014, and currently serves as the Chair of the Governance, Safety and Sustainability Committee. He is also on the Investment Performance Committee of the Board and has previously served on the Audit, Finance and Risk Committee. Mr. Dielwart is a founder and director of ARC Resources Ltd. from 1996 to present and served as Chief Executive Officer of ARC Resources Ltd. from 2001 to 2013. Mr. Dielwart earned a Bachelor of Science (Distinction) in Civil Engineering from the University of Calgary, is a member of the Association of Professional Engineers and Geoscientists of Alberta and a Past-Chairman of the Board of Governors of the Canadian Association of Petroleum Producers. Mr. Dielwart is also a director and former Co-Chair of the Calgary and Area Child Advocacy Centre. In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame.

On Jan. 25, 2019, we also announced the retirement decision of Timothy Faithfull. In 2018, Mr. Faithfull indicated to the Board his intention to retire from the Board of Directors immediately following TransAlta's 2019 Annual Shareholders Meeting.

Management Changes

On July 18, 2019, the Corporation appointed John Kousinioris as Chief Operating Officer of TransAlta Corporation. Mr. Kousinioris previously held the roles Chief Growth Officer and Chief Legal and Compliance Officer and Corporate Secretary at TransAlta. In the role of Chief Growth Officer, Mr. Kousinioris was responsible for overseeing the areas of business development, gas and renewables operations, commercial and energy marketing. Mr. Kousinioris also remains the President of TransAlta Renewables.

On May 16, 2019, the Corporation promoted Todd Stack to Chief Financial Officer. Mr. Stack, who has served as Managing Director and Corporate Controller of the Corporation since February 2017, has been responsible for providing leadership and direction over TransAlta's financial activities, corporate accounting, reporting, tax and corporate planning. Since joining TransAlta in 1990, Mr. Stack has acted as the Corporation's Treasurer and Corporate Controller, as well as a member of the corporate development team reviewing greenfield and acquisition opportunities. Prior to joining the finance team at TransAlta, Mr. Stack held a number of roles in the engineering team, including design, operations and project management.

Mothballing of Sundance Units

On Mar. 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from Apr. 1, 2020. The extensions were requested by TransAlta based on our assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

Financing of the US Wind Projects

TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta Power Ltd. ("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 US Wind Projects were funded by tax equity financing and TransAlta Renewables. As at Dec. 31, 2019, TransAlta Renewables funded these costs by acquiring tracking preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity.

Big Level and Antrim began commercial operation on Dec. 19, 2019, and Dec. 24, 2019, respectively. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US$85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the statements of financial position.

Refer to the Corporate Strategy section of this MD&A for further updates on ongoing projects.

Refer to Note 4 of the consolidated financial statements within our 2019 Annual Integrated Report for significant events impacting both prior and current year results.

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, 2019, 2018 and 2017. 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 to provide management and investors with an understanding of our financial position and results. Certain 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, deconsolidated Comparable EBITDA, FFO, deconsolidated FFO, FCF, total net debt, total consolidated net debt, adjusted net debt, deconsolidated 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, Selected Quarterly Information, Key Financial Ratios and Financial Capital sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Discussion of Consolidated Financial Results

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, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, under comparable EBITDA we reclassify certain transactions to facilitate the discussion of the performance of our business:

- During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
- Any gains or losses on asset sales are not included as these are not part of ongoing operations.
- Certain assets we own in Canada (and in Australia in 2017) 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, carbon compliance 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 Dec. 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 depreciated the facility until Dec. 31, 2018.
- On the commissioning of the South Hedland facility 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.
- In October 2019, we acquired Capital Power's 50 per cent ownership of Keephills 3 in exchange for selling our 50 per cent ownership in the Genesee 3 facility to Capital Power, and we now own 100 per cent of the Keephills 3 facility. As a result, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. Upon termination of this agreement in the fourth quarter of 2019, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings. On a comparable basis, we removed this gain from 2019 results.
- Asset impairment charges (reversals) are removed to calculate comparable EBITDA as these are accounting adjustments that impact depreciation and amortization and do not reflect business performance.

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

Year ended Dec. 31	**2019**	2018	2017
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Net earnings attributable to non-controlling interests	**94**	108	42
Preferred share dividends	**30**	50	30
Net earnings (loss)	**176**	(90)	(118)
Adjustments to reconcile net income to comparable EBITDA			
Income tax expense (recovery)	**17**	(6)	64
Gain on sale of assets and other	**(46)**	(1)	(2)
Foreign exchange loss	**15**	15	1
Net interest expense	**179**	250	247
Depreciation and amortization	**590**	574	635
Comparable reclassifications			
Decrease in finance lease receivables	**24**	59	59
Mine depreciation included in fuel cost	**121**	140	75
Australian interest income	**4**	4	2
Unrealized mark-to-market (gains) losses	**(33)**	38	(32)
Adjustments to earnings to arrive at comparable EBITDA			
Impacts to revenue associated with certain de-designated and economic hedges	**—**	—	2
Impacts associated with Mississauga recontracting(1)	**—**	105	77
Gain on termination of Keephills 3 coal rights contract	**(88)**	—	—
Asset impairment charge(2)	**25**	73	20
Comparable EBITDA	**984**	1,161	1,030
Comparable EBITDA - excluding the PPA Termination Payments	**928**	1,004	1,030

(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).

(2) Asset impairment charges for 2019 primarily includes the $141 million increase for the decommissioning and restoration liability at the Centralia mine, the $15 million for trucks held for sale and written down to net realizable value and the $18 million write-off of project development costs, partially offset by a $151 million impairment reversal at US Coal (2018 - $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).

Funds from Operations and Free Cash Flow

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

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

Year ended Dec. 31	2019	2018	2017
Cash flow from operating activities[1]	**849**	820	626
Change in non-cash operating working capital balances	**(121)**	44	114
Cash flow from operations before changes in working capital	**728**	864	740
Adjustments			
Decrease in finance lease receivable	**24**	59	59
Other	**5**	4	5
FFO	**757**	927	804
Deduct:			
Sustaining capital[2]	**(141)**	(150)	(218)
Productivity capital	**(9)**	(21)	(24)
Dividends paid on preferred shares	**(40)**	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(111)**	(169)	(172)
Payments on lease obligations[2]	**(21)**	(18)	(17)
Other	**—**	(5)	(5)
FCF	**435**	524	328
Weighted average number of common shares outstanding in the year	**283**	287	288
FFO per share	**2.67**	3.23	2.79
FCF per share	**1.54**	1.83	1.14

(1) 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

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

Year ended Dec. 31	2019	2018	2017
Comparable EBITDA[1]	**984**	1,161	1,030
Provisions and other	**13**	(9)	(3)
Interest expense	**(174)**	(187)	(218)
Current income tax expense	**(35)**	(28)	(23)
Realized foreign exchange gain (loss)	**(6)**	5	15
Decommissioning and restoration costs settled	**(34)**	(31)	(19)
Other cash and non-cash items	**9**	16	22
FFO	**757**	927	804
Deduct:			
Sustaining capital[2]	**(141)**	(150)	(218)
Productivity capital	**(9)**	(21)	(24)
Dividends paid on preferred shares	**(40)**	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	**(111)**	(169)	(172)
Payments on lease obligations[2]	**(21)**	(18)	(17)
Other	**—**	(5)	(5)
FCF	**435**	524	328

(1) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change. 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

Supplemental disclosure	**2019**	2018	2017
FFO - excluding the PPA Termination Payments	**701**	770	804
FCF - excluding the PPA Termination Payments	**379**	367	328
FFO per share - excluding the PPA Termination Payments	**2.48**	2.68	2.79
FCF per share - excluding the PPA Termination Payments	**1.34**	1.28	1.14

For explanations for the current period, refer to the Highlights section of this MD&A.

Higher FCF in 2018 compared to 2017 was also driven by strong cash flow from operating activities due to the receipt of the $157 million PPA Termination Payments in 2018 related to the termination of the Sundance B and C PPAs, as well as reduced sustaining and productivity capital expenditures.

Segmented Comparable Results

Segmented cash flow 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.

The table below shows the segmented cash flow generated by the business by each of our segments:

Year ended Dec. 31	**2019**	2018	2017
Segmented cash flow(1)			
Canadian Coal(2)	**214**	279	175
US Coal	**54**	63	33
Canadian Gas(3)	**99**	228	221
Australian Gas	**112**	136	127
Wind and Solar	**206**	211	201
Hydro	**93**	96	61
Generation segmented cash flow	**778**	1,013	818
Energy Marketing	**105**	33	39
Corporate	**(92)**	(107)	(108)
Total segmented cash flow	**791**	939	749
Total segmented cash flow - excluding the PPA Termination Payments	**735**	782	749

(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) Includes $157 million received from the Balancing Pool for the early termination of Sundance B and C PPAs in the first quarter of 2018 and $56 million received on settlement of the dispute with the Balancing Pool in the third quarter of 2019. See the Significant and Subsequent Events section for further details.
(3) 2017 includes $34 million from the OEFC relating to the 2017 indexation dispute.

Segmented cash flow generated by the business, after adjusting for the PPA Termination Payments, was down $47 million in 2019 compared to 2018, mainly due to the expiry of the Mississauga NUG Contract and lower scheduled repayments on the Poplar Creek finance lease, partially offset by strong cash flow from Energy Marketing as well as lower sustaining capital expenditures. Cash flow in 2018 was $33 million higher than 2017 due to lower sustaining capital expenditures and higher Ancillary Services revenue from our hydro facilities.

Canadian Coal

Year ended Dec. 31	**2019**	2018	2017
Availability (%)	**89.2**	91.6	82.0
Contract production (GWh)	**6,927**	8,936	18,683
Merchant production (GWh)	**5,932**	5,304	3,786
Total production (GWh)	**12,859**	14,240	22,469
Gross installed capacity (MW)[(1)]	**3,229**	3,231	3,791
Revenues[(2)]	**823**	901	996
Fuel, carbon compliance and purchased power	**449**	526	510
Comparable gross margin	**374**	375	486
Operations, maintenance and administration	**138**	171	192
Taxes, other than income taxes	**13**	13	13
Termination of Sundance B and C PPAs	**(56)**	(157)	—
Net other operating income	**(40)**	(41)	(40)
Comparable EBITDA[(2)]	**319**	389	321
Deduct:			
Sustaining capital:			
Routine capital	**15**	17	22
Mine capital	**23**	42	28
Planned major maintenance	**34**	15	54
Total sustaining capital expenditures[(3)]	**72**	74	104
Productivity capital	**6**	12	12
Total sustaining and productivity capital[(3)]	**78**	86	116
Provisions	**(6)**	(10)	5
Payments on lease obligations[(3)]	**16**	14	14
Decommissioning and restoration costs settled	**17**	19	11
Other	**—**	1	—
Canadian Coal cash flow	**214**	279	175

(1) 2019 & 2018 - includes 774 MW for Sundance Units 3 and 5, which are temporarily mothballed; 2017 includes 1,334 MW for Sundance Units 1, 2, 3 and 5, which were temporarily mothballed. Sundance Unit 1 was retired on Jan. 1, 2018, and Sundance Unit 2 was retired on July 31, 2018. The Keephills 3 and Genesee 3 asset swap resulted in a net 2 MW reduction of capacity.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) On implementation of IFRS 16 in 2019, we removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line in arriving at segmented cash flow.

Supplemental disclosure	**2019**	2018	2017
Comparable EBITDA - excluding the PPA Termination Payments	**263**	232	321
Canadian Coal cash flow - excluding the PPA Termination Payments	**158**	122	175

2019

Availability for the year was lower compared to 2018, due to planned outages at our Keephills 1 and Sundance 4 units, whereas 2018 only had one outage at one of our non-operated units; this was partially offset by fewer unplanned losses in 2019.

Production for the year ended Dec. 31, 2019, decreased 1,381 gigawatt hours ("GWh") compared to 2018, primarily due to the mothballing of certain Sundance units and planned outages, partially offset by lower unplanned outages. Lower contract production was partially offset by higher merchant production.

Revenue for the year ended Dec. 31, 2019, decreased by $78 million compared to 2018, mainly due to lower production as a result of the termination of the Sundance B and C PPAs on Mar. 31, 2018.

Revenue per MWh of production rose to approximately $64 per MWh in 2019 from $63 per MWh in 2018. Revenues in the first quarter of 2018 included the Sundance B and C PPA revenue as well as the passthrough revenues associated with carbon compliance costs, which are no longer recoverable on the Sundance units as the PPAs have been terminated.

Fuel, carbon compliance and purchased power costs per MWh were lower in 2019 compared to 2018. Cost per MWh of production fell to approximately $35 per MWh in 2019 from $37 per MWh in 2018. Consequently, comparable gross margin per MWh for 2019 improved by approximately $3 per MWh compared to 2018.

We continued to co-fire with natural gas, when economical. Natural gas combustion produces fewer GHG emissions than coal combustion, which lowers our GHG compliance costs. In addition, fuel costs can be lower by co-firing, depending on the market price for natural gas. On Nov. 1, 2019, the firm contract to transport natural gas on the Pioneer Pipeline began, which substantially increased gas quantities available to us and increased our supply available to co-fire.

OM&A costs were lower in 2019 compared to 2018, as a result of the full year impact of cost reductions progressively implemented over the preceding year. These cost reductions arose from a combination of factors including fewer units operating, lower capacity factor operation on merchant units, co-firing with gas, and operations and maintenance work optimization.

Excluding the PPA Termination Payments, comparable EBITDA for the year ended Dec. 31, 2019, increased $31 million compared to 2018. This largely reflects lower fuel, carbon compliance, and purchased power costs, as well as lower OM&A costs.

For the year ended Dec. 31, 2019, sustaining capital expenditures decreased by $2 million compared to 2018, mainly due to less mine development work being completed in 2019, partially offset by higher spend on planned major maintenance. In 2018, there was only one planned major outage at one of our non-operating units, while during 2019 there were two planned major outages at the Keephills 1 and Sundance 4 units.

Canadian Coal cash flow for the year ended Dec. 31, 2019, increased by $36 million (excluding the PPA Termination Payments) compared to 2018, mainly due to higher comparable EBITDA and decreased sustaining and productivity capital expenditures.

2018

Availability in 2018 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 by 8,229 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 $95 million compared to 2017, mainly due to lower production offset by higher prices. Revenue per MWh of production rose to approximately $63 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 2018, we commenced co-firing with natural gas. 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 continued to optimize the operations of the facility in response to the merchant market.

Comparable EBITDA for the year ended Dec. 31, 2018, increased $68 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 were four fewer units in the fleet to maintain, which significantly reduced our sustaining capital costs.

US Coal

Year ended Dec. 31	2019	2018	2017
Availability (%)	**74.0**	60.2	66.3
Adjusted availability (%)[1]	**83.5**	84.6	86.2
Contract sales volume (GWh)	**3,329**	3,329	3,609
Merchant sales volume (GWh)	**7,691**	5,704	5,488
Purchased power (GWh)	**(3,865)**	(3,665)	(3,625)
Total production (GWh)	**7,155**	5,368	5,472
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues[2]	**559**	471	427
Fuel and purchased power	**416**	314	293
Comparable gross margin	**143**	157	134
Operations, maintenance and administration	**67**	61	51
Taxes, other than income taxes	**3**	5	4
Comparable EBITDA[2]	**73**	91	79
Deduct:			
Sustaining capital:			
Routine capital	**2**	2	3
Planned major maintenance	**5**	11	29
Total sustaining capital expenditures[3]	**7**	13	32
Productivity capital	**1**	—	3
Total sustaining and productivity capital[3]	**8**	13	35
Payments on lease obligations[3]	**—**	4	3
Decommissioning and restoration costs settled	**11**	11	8
US Coal cash flow	**54**	63	33

(1) Adjusted for dispatch optimization.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) On implementation of IFRS 16 in 2019, we have removed the finance leases from sustaining capital and included principal payments on lease obligations as a separate line. The contractual arrangement that was accounted for as a finance lease in 2018 and prior periods is not considered a lease under IFRS 16. Accordingly, the costs are reflected in fuel and purchased power and there are no payments on lease obligations from Jan. 1, 2019.

2019

Adjusted availability for the year was down compared to 2018 due to higher forced outages and derates in 2019. Centralia Unit 1 operated with a derate due to blocked precipitator hoppers impacting the first half of 2019. This derate was resolved when the unit was offline during the second quarter of 2019.

Production was up 1,787 GWh in 2019 compared to 2018, due mainly to higher merchant pricing in the first half of 2019 and timing of dispatch optimization. In 2019, both Centralia units remained in service into April due to higher prices in the Pacific Northwest, whereas in 2018, both Centralia units were taken out of service in February as a result of seasonally lower prices in the Pacific Northwest. In 2018, we performed major maintenance on both units during that time.

OM&A costs were $6 million higher in 2019 compared to 2018, mainly due to higher levels of maintenance required to support a 33 per cent increase in production and as a result of higher costs to resolve precipitator blockages.

Comparable EBITDA decreased by $18 million compared to 2018, primarily due to an isolated and extreme pricing event in March. Centralia was unable to commit one of its units to physical production for day-ahead supply due to an unplanned forced outage repair.

Sustaining and productivity capital expenditures for 2019 were $5 million lower than 2018, mainly due to less planned outage work performed in 2019.

US Coal's cash flow for 2019 decreased by $9 million compared to the prior year, mainly due to lower comparable EBITDA, partially offset by lower sustaining and productivity capital spend.

2018

Availability for 2018 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 2018 and 2017, 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 increased by $12 million compared to 2017, primarily due to reduced coal costs and favourable market prices.

Sustaining and productivity capital expenditures for 2018 were $22 million lower than 2017, due to lower planned outages.

US Coal's 2018 cash flow improved by $30 million compared to 2017, mainly due to stronger comparable EBITDA and lower sustaining and productivity capital spend.

Canadian Gas

Year ended Dec. 31	**2019**	2018	2017
Availability (%)	**94.8**	93.3	91.6
Contract production (GWh)	**1,655**	1,620	1,504
Merchant production (GWh)[(1)]	**170**	93	244
Total production (GWh)	**1,825**	1,713	1,748
Gross installed capacity (MW)[(2)]	**945**	945	952
Revenues[(3)]	**238**	407	423
Fuel and purchased power	**74**	99	113
Comparable gross margin	**164**	308	310
Operations, maintenance and administration	**44**	48	53
Taxes, other than income taxes	**1**	1	1
Net other operating income	**(1)**	—	—
Comparable EBITDA[(3)]	**120**	259	256
Deduct:			
Sustaining capital:			
Routine capital	**10**	4	8
Planned major maintenance	**8**	16	22
Total sustaining capital expenditures	**18**	20	30
Productivity capital	**—**	2	2
Total sustaining and productivity capital	**18**	22	32
Provisions and other	**—**	9	3
Decommissioning and restoration costs settled	**3**	—	—
Canadian Gas cash flow	**99**	228	221

(1) Includes purchased power, which is used for dispatch optimization, when economical.
(2) Excludes capacity of Mississauga, which was mothballed in early 2017. All years include production capacity for the Fort Saskatchewan facility, which has been accounted for as a finance lease. During 2015, operational control of our Poplar Creek facility was transferred to Suncor Energy. We continue to own a portion of the facility and have included our portion as a part of gross capacity measures.
(3) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

2019

Availability for the year ended Dec. 31, 2019, increased compared to 2018, primarily due to lower planned outages at Fort Saskatchewan and Sarnia.

Production for the year increased by 112 GWh compared to 2018, mainly due to higher customer and market demand as well as lower planned outages, which was partially offset by higher unplanned outages.

Comparable EBITDA for 2019 decreased by $139 million compared to 2018, mainly due to the Mississauga contract ending Dec. 31, 2018 and lower scheduled payments from the Poplar Creek finance lease. Comparable EBITDA for the year ended Dec. 31, 2019, includes nil (2018 - $105 million) and $20 million (2018 - $57 million) from the Mississauga and Poplar Creek contracts, respectively. Additionally, comparable EBITDA benefited from lower OM&A compared to the prior year as a result of reduced overhead and operating costs.

Sustaining capital totalled $18 million in 2019, a decrease of $2 million due to lower planned outage costs, partially offset by the timing of capital spares purchases for Sarnia.

Cash flow at Canadian Gas decreased by $129 million for the year ended Dec. 31, 2019, compared to the prior year mainly due to lower comparable EBITDA.

2018

Availability for the year ended Dec. 31, 2018, increased 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 by 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 in 2018.

Comparable EBITDA for 2018 increased by $3 million compared to 2017, mainly due to the positive impact from the Mississauga recontracting, higher realized pricing at Sarnia and cost reduction initiatives, partially offset by the retroactive contract indexation dispute settlement with the OEFC in 2017 ($34 million). 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 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.

Australian Gas

Year ended Dec. 31	2019	2018	2017
Availability (%)	**90.6**	94.0	93.4
Contract production (GWh)	**1,832**	1,814	1,803
Gross installed capacity (MW)[(1)]	**450**	450	450
Revenues	**160**	165	180
Fuel and purchased power	**5**	4	12
Comparable gross margin	**155**	161	168
Operations, maintenance and administration	**37**	37	31
Comparable EBITDA	**118**	124	137
Deduct:			
Sustaining capital:			
Routine capital	**2**	2	9
Planned major maintenance	**3**	—	1
Total sustaining capital expenditures	**5**	2	10
Productivity capital	**1**	—	—
Total sustaining and productivity capital	**6**	2	10
Other	**—**	(14)	—
Australian Gas cash flow	**112**	136	127

(1) In 2017, Fortescue Metals Group Ltd. ("FMG") repurchased the Solomon facility and therefore it was removed from 2017 capacity, which was offset by adding capacity for the South Hedland facility, which achieved commercial operations on July 28, 2017.

2019

Availability for the year ended Dec. 31, 2019, decreased compared to 2018, mainly due to unplanned outages.

Production for 2019 was comparable to 2018. 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 customer supplied fuel or a passthrough of fuel costs.

Comparable EBITDA for the year ended Dec. 31, 2019, decreased by $6 million compared to 2018, due to the weakening of the Australian dollar and ongoing legal costs associated with our disputes with FMG.

Sustaining and productivity capital for 2019 increased by $4 million compared to 2018, mainly due to planned major maintenance at our Southern Cross facility.

Cash flow at Australian Gas decreased by $24 million in 2019, mainly due to lower comparable EBITDA as well as higher sustaining capital expenditures. In addition, 2018 cash flow included the collection of a long-term receivable.

2018

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

Comparable EBITDA for the year decreased by $13 million compared to 2017 mainly due to FMG's repurchase of the Solomon facility, higher OM&A costs due to the addition of the South Hedland facility and ongoing legal costs associated with our disputes with FMG, which were partially offset by higher EBITDA from the South Hedland facility. Refer to the Other Consolidated Analysis section of this MD&A for further details.

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.

Wind and Solar

Year ended Dec. 31	2019	2018	2017
Availability (%)	**95.0**	95.4	95.8
Contract production (GWh)	**2,395**	2,363	2,362
Merchant production (GWh)	**960**	1,005	1,098
Total production (GWh)	**3,355**	3,368	3,460
Gross installed capacity (MW)(1)	**1,495**	1,382	1,363
Revenues(2)	**295**	302	287
Fuel and purchased power	**16**	17	17
Comparable gross margin	**279**	285	270
Operations, maintenance and administration	**50**	50	48
Taxes, other than income taxes	**8**	8	8
Net other operating income(3)	**(10)**	(6)	—
Comparable EBITDA(2)	**231**	233	214
Deduct:			
Sustaining capital:			
Routine capital	**2**	5	1
Planned major maintenance	**11**	8	10
Total sustaining capital expenditures	**13**	13	11
Productivity capital	**—**	2	2
Total sustaining and productivity capital	**13**	15	13
Payments on lease obligations(4)	**1**	—	—
Decommissioning and restoration costs settled	**1**	1	—
Other(3)	**10**	6	—
Wind and Solar cash flow	**206**	211	201

(1) The 2019 installed capacity includes the addition of Big Level and Antrim in late December, partially offset by the reduction of wind turbines due to tower fires at Wyoming Wind and Summerview.
(2) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.
(3) Relates to insurance proceeds included in net other operating income.
(4) On implementation of IFRS 16 in 2019, we have included principal payments on lease obligations as a separate line.

2019
Availability and production for the year ended Dec. 31, 2019, was comparable to 2018, which was in line with our expectations. The Big Level and Antrim wind farms had minimal impact on 2019 availability and production due to their commercial operation occurring in late December.

Comparable EBITDA for 2019 was consistent with 2018. Higher insurance proceeds from tower fires at Wyoming Wind and Summerview were partially offset by a reduction in revenues due to the scheduled expiration of production-based incentives for three wind facilities.

Wind and Solar's cash flow decreased by $5 million for the year ended Dec. 31, 2019, compared to the prior year, mainly due to lower revenue.

2018
Availability for the year ended Dec. 31, 2018, was comparable to 2017, which was in line with our expectations.

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

Comparable EBITDA for 2018 was higher than 2017, due to higher merchant prices in Alberta and insurance proceeds from the tower fire at the Wyoming Wind farm, which was partially offset by 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 higher comparable EBITDA, partially offset by the adjustment to remove the insurance proceeds from cash flow.

Hydro

Year ended Dec. 31	2019	2018	2017
Production			
Energy contracted			
Alberta Hydro PPA assets (GWh)(1)	**1,653**	1,519	1,530
Other hydro energy (GWh)(1)	**331**	306	336
Energy merchant			
Other hydro energy (GWh)	**61**	81	82
Total energy production (GWh)	**2,045**	1,906	1,948
Ancillary service volumes (GWh)(2)	**2,978**	3,265	3,044
Gross installed capacity (MW)	**926**	926	926
Revenues			
Alberta Hydro PPA assets energy	**101**	90	36
Alberta Hydro PPA assets ancillary	**90**	104	36
Capacity payments received under Alberta Hydro PPA(3)	**57**	56	54
Other revenue(4)	**44**	41	43
Total gross revenues	**292**	291	169
Net payment relating to Alberta Hydro PPA(5)	**(136)**	(135)	(48)
Revenues	**156**	156	121
Fuel and purchased power	**7**	6	6
Comparable gross margin	**149**	150	115
Operations, maintenance and administration	**36**	38	37
Taxes, other than income taxes	**3**	3	3
Comparable EBITDA	**110**	109	75
Deduct:			
Sustaining capital:			
Routine capital	**7**	4	8
Planned major maintenance	**7**	8	5
Total sustaining capital expenditures	**14**	12	13
Productivity capital	**1**	1	1
Total sustaining and productivity capital	**15**	13	14
Decommissioning and restoration costs settled	**2**	—	—
Hydro cash flow	**93**	96	61

(1) Alberta Hydro PPA assets include 13 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. The PPA expires on Dec. 31, 2020.
(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.
(5) The net payment relating to the Alberta Hydro PPA represents the Corporation's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA which expires on Dec. 31, 2020.

2019
Production for 2019 increased by 139 GWh over 2018, primarily due to higher water resources.

Total gross revenues were comparable to 2018, as the Hydro business optimizes its revenue through a combination of energy sales and Ancillary Services, which allows us to maintain consistent revenues year-over-year.

Comparable EBITDA for 2019 increased by $1 million compared to 2018, as we were able to reduce OM&A due to cost-saving initiatives, while absorbing the $1.5 million Brookfield Hydro Fee. Refer to the Corporate Strategy and Significant and Subsequent Events section of this MD&A for further details.

Hydro's cash flow decreased by $3 million for 2019 compared to 2018, mainly due to higher capital expenditures and decommissioning costs related to transmission assets.

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.

Energy Marketing

Year ended Dec. 31	**2019**	2018	2017
Revenues and comparable gross margin(1)	**119**	67	57
Operations, maintenance and administration	**30**	24	24
Comparable EBITDA(1)	**89**	43	33
Deduct:			
Provisions and other	**(16)**	10	(6)
Energy Marketing cash flow	**105**	33	39

(1) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

2019
Comparable EBITDA for 2019 increased by $46 million compared to 2018 results, due to strong results from all Marketing segments, with particularly strong performance from US Western and Eastern markets due to continued high levels of volatility. OM&A increased due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short-term arbitrage opportunities in the markets in which we trade without materially changing the risk profile of the business unit.

Energy Marketing's cash flows for 2019 increased by $72 million compared to 2018, mainly due to higher Comparable EBITDA and other cash settlements.

2018
Comparable EBITDA for 2018, excluding unrealized mark-to-market gains or losses, was $10 million higher than 2017 due to strong results from most marketing segments, with particularly strong performance from the US Western market and year-over-year improvements in natural gas markets.

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.

Corporate

Year ended Dec. 31	2019	2018	2017
Operations, maintenance, and administration	**73**	86	84
Taxes, other than income taxes	**1**	1	1
Net other operating loss	**2**	—	—
Comparable EBITDA	**(76)**	(87)	(85)
Deduct:			
Sustaining capital:			
Routine capital	**12**	16	18
Total sustaining capital expenditures	**12**	16	18
Productivity capital	**—**	4	4
Total sustaining and productivity capital expenditures	**12**	20	22
Provisions	**—**	—	1
Payments on lease obligations(1)	**4**	—	—
Corporate cash flow	**(92)**	(107)	(108)

(1) On implementation of IFRS 16 in 2019, we have included principal payments on lease obligations as a separate line.

2019

Our Corporate overhead costs in 2019 were $76 million, a decrease of $11 million compared to $87 million in 2018, primarily due to cost-efficiency initiatives and payments on lease obligations. In addition, we realized a net gain of $13 million from the total return swap on our share-based payment plans, which was mostly offset by higher legal fees. A portion of the settlement cost of our share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter. Corporate cash flow also benefited from lower sustaining and productivity capital spend due to higher spend in 2018 on automation and new information technology solutions implemented in prior years, which helped contribute to the cost efficiencies realized in 2019.

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 included $20 million (2017 - $22 million) in sustaining and productivity capital spend.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2019	2018
Revenues	**609**	622
Fuel, carbon compliance and purchased power	**286**	336
Operations, maintenance and administration	**127**	139
Net earnings (loss) attributable to common shareholders	**66**	(122)
Cash flow from operating activities	**181**	132
Comparable EBITDA(1)	**243**	265
FFO(1)	**189**	217
FCF(1)	**121**	98
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.24**	(0.43)
FFO per share(1)	**0.67**	0.76
FCF per share(1)	**0.43**	0.34
Dividends declared per common share(3)	**0.04**	0.08
Dividends declared per preferred share(4)	**0.26**	0.52

(1) These items are not defined and have no standardized meaning 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. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.

(2) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

(3) Dividends declared vary year over year due to timing of dividend declarations.

(4) 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.

Financial Highlights

We delivered strong results in the fourth quarter with FCF of $121 million, compared to $98 million last year, mainly due to lower sustaining capital expenditures and distributions paid to subsidiaries, partially offset by lower comparable EBITDA. FFO was $189 million, which was $28 million lower than the fourth quarter of 2018, also mainly due to lower comparable EBITDA.

Net earnings attributable to common shareholders in the fourth quarter of 2019 was $66 million ($0.24 net earnings per share) compared to a net loss of $122 million ($0.43 net loss per share) in the same period of 2018, an improvement of $188 million. This was driven partially by the Keephills 3 and Genesee 3 swap with Capital Power where we recognized a gain on termination of the coal rights contract of $88 million and a gain on the sale of Genesee 3 of $77 million (refer to the Highlights and Significant and Subsequent Events sections of this MD&A for further details). In addition, the fourth quarter showed the impact of cost-saving initiatives in OM&A, fuel, carbon compliance and purchased power costs as well as lower interest expense, partially offset by higher impairment charges, losses on sale of PP&E and higher income tax expense.

Segmented Cash Flow Generated by the Business and Operational Performance

Segmented cash flow 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 flow available to pay our interest and cash taxes, distributions to our non-controlling partners, dividends to our preferred shareholders and to grow the business, pay down debt and return capital to our shareholders.

Segmented cash flow and operational performance for the business for the three months ended Dec. 31, 2019 and 2018 is as follows:

Three months ended Dec. 31	**2019**	2018
Availability (%)(1)	**91.6**	91.5
Production (GWh)(1)	**8,153**	8,276
Segmented cash flow(2)		
Canadian Coal	**37**	16
US Coal	**25**	21
Canadian Gas	**22**	59
Australian Gas	**25**	35
Wind and Solar	**72**	74
Hydro	**13**	11
Generation segmented cash flow	**194**	216
Energy Marketing	**31**	10
Corporate	**(29)**	(34)
Total segmented cash flow	**196**	192

(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 and has no standardized meaning 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. See also the Additional IFRS measures and Non-IFRS Measures section of this MD&A.

Availability for the three months ended Dec. 31, 2019, was comparable with the same period in 2018. Lower production for the three months ended Dec. 31, 2019, compared to the same period in 2018 is primarily due to paid curtailments at Canadian Coal and lower wind resources, partially offset by higher production at US Coal.

Comparable cash flow generated by the business totalled $196 million in the fourth quarter, an increase of $4 million compared with last year's performance. Increased cash flow is largely due to the strong performance at Canadian Coal and Energy Marketing, partially offset by lower cash flow at Canadian Gas as a result of the termination of the Mississauga contract as well as lower scheduled payments at Poplar Creek. In addition, 2018 comparable cash flow benefited from the settlement of a long-term receivable in Australian Gas.

Discussion of Consolidated Financial Results for the Fourth Quarter

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	2019	2018
Net earnings (loss) attributable to common shareholders	**66**	(122)
Net earnings attributable to non-controlling interests	**27**	43
Preferred share dividends	**10**	20
Net earnings (loss)	**103**	(59)
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**40**	(16)
Gain on sale of assets and other	**(64)**	—
Foreign exchange (gain) loss	**(3)**	—
Net interest expense	**18**	50
Depreciation and amortization	**154**	152
Comparable reclassifications		
Decrease in finance lease receivables	**5**	15
Mine depreciation included in fuel cost	**31**	37
Australian interest income	**1**	1
Unrealized mark-to-market (gains) losses	**(1)**	32
Adjustments to earnings to arrive at comparable EBITDA		
Impacts to revenue associated with certain de-designated and economic hedges	**—**	—
Impacts associated with Mississauga recontracting(1)	**—**	30
Gain on termination of Keephills 3 coal rights contract	**(88)**	—
Asset impairment charge(2)	**47**	23
Comparable EBITDA	**243**	265

(1) Impacts associated with Mississauga recontracting for the three months ended Dec. 31, 2019, are as follows: revenue nil (2018 - $30 million).
(2) Asset impairment charges for the three months ended Dec. 31, 2019, include $32 million increase for the decommissioning and restoration liability at the Centralia mine and $15 million for trucks held for sale and written down to net realizable value (2018 - includes the write-off of project development costs of $23 million).

A summary of our comparable EBITDA by segment for the three months ended Dec. 31, 2019 and 2018 is as follows:

Three months ended Dec. 31	2019	2018
Comparable EBITDA		
Canadian Coal	**55**	48
US Coal	**29**	24
Canadian Gas	**29**	74
Australian Gas	**28**	32
Wind and Solar	**80**	82
Hydro	**18**	17
Energy Marketing	**26**	16
Corporate	**(22)**	(28)
Total Comparable EBITDA	**243**	265

Comparable EBITDA decreased by $22 million for the fourth quarter 2019, compared to 2018, primarily as a result of:

- Our Canadian Coal results were up $7 million mainly due to lower OM&A in 2019.
- US Coal results were up $5 million primarily due to lower fuel and purchased power costs and increased volumes.
- Our Canadian Gas business was down $45 million mainly due to the Mississauga contract ending in 2018 and lower scheduled payments from Poplar Creek.
- Australian Gas was down $4 million, mainly due to the weakening of the Australian dollar and slightly higher legal costs.
- Wind and Solar results were down $2 million period-over-period mainly due to lower revenues due to the scheduled expirations of production-based incentives for wind facilities.
- Hydro results were $1 million higher and therefore fairly consistent, which was in line with our expectations.
- Energy Marketing's comparable EBITDA was up $10 million, mainly due to continued high levels of volatility in the market.
- Corporate costs decreased by $6 million in the fourth quarter mainly due to the realized net gain from the total return swap on our share-based payment plans and cost-saving efficiencies.

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 in this MD&A for further details.

The table below reconciles our cash flow from operating activities to our FFO and FCF for the three months ended Dec. 31, 2019 and 2018:

Three months ended Dec. 31	**2019**	2018
Cash flow from operating activities	**181**	132
Change in non-cash operating working capital balances	**1**	69
Cash flow from operations before changes in working capital	**182**	201
Adjustments		
Decrease in finance lease receivable	**5**	15
Other	**2**	1
FFO	**189**	217
Deduct:		
Sustaining capital	**(30)**	(52)
Productivity capital	**(2)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(22)**	(43)
Payments on lease obligations[1]	**(5)**	(4)
Other	**1**	(1)
FCF	**121**	98
Weighted average number of common shares outstanding in the period	**280**	286
FFO per share	**0.67**	0.76
FCF per share	**0.43**	0.34

(1) During the first quarter of 2019, we revised the way in which FFO and FCF are reconciled to reflect the payments related to lease obligations as a separate line and removed finance leases from sustaining capital. Prior period results have been revised to reflect these changes.

The table below provides a reconciliation of our comparable EBITDA to our FFO and FCF for the three months ended Dec. 31, 2019 and 2018:

Three months ended Dec. 31	**2019**	2018
Comparable EBITDA	**243**	265
Provisions	**(1)**	(5)
Interest expense	**(41)**	(40)
Current income tax expense	**(7)**	(10)
Realized foreign exchange gain (loss)	**1**	1
Decommissioning and restoration costs settled	**(10)**	(8)
Other non-cash items	**4**	14
FFO	**189**	217
Deduct:		
Sustaining capital	**(30)**	(52)
Productivity capital	**(2)**	(9)
Dividends paid on preferred shares	**(10)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(22)**	(43)
Payments on lease obligations	**(5)**	(4)
Other	1	(1)
Comparable FCF	**121**	98
Weighted average number of common shares outstanding in the period	**280**	286
Comparable FFO per share	**0.67**	0.76
Comparable FCF per share	**0.43**	0.34

Selected Quarterly Information

Our results are seasonal due to the nature of the electricity market and related fuel costs. Higher maintenance costs are often 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 2019	Q2 2019	Q3 2019	**Q4 2019**
Revenues	648	497	593	**609**
Comparable EBITDA[1]	221	215	305	**243**
FFO	169	155	244	**189**
Net earnings (loss) attributable to common shareholders	(65)	—	51	**66**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[2]	(0.23)	—	0.18	**0.24**
	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	588	446	593	622
Comparable EBITDA[1]	396	248	252	265
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[2]	0.23	(0.36)	(0.30)	(0.43)

(1) During the first quarter of 2019, we revised our approach to reporting adjustments to arrive at comparable EBITDA, mainly to be more comparable with other companies in the industry. Comparable EBITDA is now adjusted to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

(2) 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 the cold winter months 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:

- Gains relating to the Keephills 3 and Genesee 3 swap in the fourth quarter of 2019;
- Effects of impairment charges and reversals during the third and fourth quarters of 2019 and impairment charges during the second, third and fourth quarters of 2018;
- Effects of changes in useful lives of certain assets during the third quarter of 2019;
- Change in income tax rates in Alberta in the second quarter of 2019;
- Lower scheduled payments commencing in January 2019 from the Poplar Creek finance lease; and
- Recognition of the $157 million early termination payment received regarding Sundance B and C PPAs during the first quarter of 2018 and $56 million received on winning the arbitration against the Balancing Pool in the third quarter of 2019.

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 and have no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies. We maintained a strong and flexible financial position in 2019.

Funds from Operations before Interest to Adjusted Interest Coverage

For the year ended Dec. 31	2019	2018	2017
FFO[(1)]	**757**	927	804
Less: PPA Termination Payments	**(56)**	(157)	—
Add: Interest on debt, exchangeable securities and leases, net of interest income and capitalized interest	**166**	174	205
FFO before interest	**867**	944	1,009
Interest on debt, exchangeable securities and leases, net of interest income	**172**	176	214
Add: 50 per cent of dividends paid on preferred shares	**20**	20	20
Adjusted interest	**192**	196	234
FFO before interest to adjusted interest coverage (times)	**4.5**	4.8	4.3

(1) See the Discussion of Consolidated Financial Results section in this MD&A for reconciliation of cash flow from operating activities to FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.

Our target for FFO before interest to adjusted interest coverage is four to five times. While all periods are within our target range, the ratio decreased slightly in 2019 compared to 2018, mainly due to lower FFO before interest.

Adjusted FFO to Adjusted Net Debt

As at Dec. 31	2019	2018	2017
FFO[1, 2]	757	927	804
Less: PPA Termination Payments[1]	(56)	(157)	—
Less: 50 per cent of dividends paid on preferred shares[1]	(20)	(20)	(20)
Adjusted FFO[1]	681	750	784
Period-end long-term debt[3]	3,212	3,267	3,707
Exchangeable securities	326	—	—
Less: Cash and cash equivalents	(411)	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	(10)	(27)	—
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt[4]	(7)	(10)	(30)
Adjusted net debt	3,581	3,612	3,834
Adjusted FFO to adjusted net debt (%)	19.0	20.8	20.4

(1) Last 12 months.
(2) Refer to the Discussion of Consolidated Financial Results section of this MD&A for the reconciliation of cash flow from operating activities to FFO. See also the IFRS Measures and Non-IFRS Measures section for further details.
(3) Includes lease obligations and tax equity financing.
(4) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.

Our target range for adjusted FFO to adjusted net debt is 20 to 25 per cent. Our adjusted FFO to adjusted net debt declined due to lower adjusted FFO compared with 2018, partially offset by lower adjusted net debt. We reached the low end of our target range of 20 to 25 per cent in 2017 and 2018.

Adjusted Net Debt to Comparable EBITDA

As at Dec. 31	2019	2018	2017
Period-end long-term debt[1]	3,212	3,267	3,707
Exchangeable securities	326	—	—
Less: Cash and cash equivalents	(411)	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	(10)	(27)	—
Add: 50 per cent of issued preferred shares	471	471	471
Fair value asset of hedging instruments on debt[2]	(7)	(10)	(30)
Adjusted net debt	3,581	3,612	3,834
Comparable EBITDA[3,4]	984	1,161	1,030
Less: PPA Termination Payments[3,4]	(56)	(157)	—
Adjusted comparable EBITDA[3,4]	928	1,004	1,030
Adjusted net debt to adjusted comparable EBITDA (times)	3.9	3.6	3.7

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.
(3) Last 12 months.
(4) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio increased compared to 2018, mainly due to the decrease in adjusted comparable EBITDA during the year, after adjusting for the PPA Termination Payments.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage excluding the portion of TransAlta Renewables and TA Cogen that are not owned by TransAlta. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at Dec. 31	2019	2018	2017
Period-end long-term debt(1)	**3,212**	3,267	3,707
Exchangeable securities	**326**	—	—
Less: Cash and cash equivalents	**(411)**	(89)	(314)
Less: Principal portion of TransAlta OCP restricted cash	**(10)**	(27)	—
Add: 50 per cent of issued preferred shares	**471**	471	471
Fair value asset of hedging instruments on debt(2)	**(7)**	(10)	(30)
Less: TransAlta Renewables long-term debt	**(961)**	(932)	(1,043)
Less: US tax equity financing(3)	**(145)**	(28)	(31)
Deconsolidated net debt	**2,475**	2,652	2,760
Comparable EBITDA(4, 5)	**984**	1,161	1,030
Less: PPA Termination Payments(4)	**(56)**	(157)	—
Less: TransAlta Renewables comparable EBITDA(4)	**(438)**	(430)	(424)
Less: TA Cogen comparable EBITDA(4)	**(80)**	(181)	(182)
Add: Dividend from TransAlta Renewables(4)	**151**	151	140
Add: Dividend from TA Cogen(4)	**37**	86	86
Deconsolidated comparable EBITDA (4, 5)	**598**	630	650
Deconsolidated net debt to deconsolidated comparable EBITDA(4, 5) (times)	**4.1**	4.2	4.2

(1) Includes lease obligations and tax equity financing.
(2) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2019, Dec. 31, 2018, and Dec. 31, 2017.
(3) Relates to assets where TransAlta Renewables has economic interests.
(4) Last 12 months.
(5) During the first quarter of 2019, we revised comparable EBITDA to exclude the impact of unrealized mark-to-market gains or losses. The current and prior period amounts have been adjusted to reflect this change.

Our target for deconsolidated net debt to deconsolidated comparable EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated comparable EBITDA ratio improved slightly compared with 2018, as lower deconsolidated net debt was partially offset by lower deconsolidated comparable EBITDA.

Deconsolidated FFO

During the third quarter of 2019, the Corporation implemented a new dividend policy that aims to return 10 to 15 per cent of TransAlta's deconsolidated FFO to shareholders as it aligns shareholder returns to the assets held directly at TransAlta. This metric is not defined and has no standardized meaning under IFRS, and may not be comparable to those used by other entities or by rating agencies. See also the IFRS Measures and Non-IFRS Measures section of this MD&A for further details. Deconsolidated FFO for the years ended Dec. 31 is detailed below:

			2019			2018			2017
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**849**	**331**		820	385		626	290	
Change in non-cash operating working capital balances	**(121)**	**(23)**		44	5		114	17	
Cash flow from operations before changes in working capital	**728**	**308**		864	390		740	307	
Adjustments:									
Decrease in finance lease receivable	**24**	**—**		59	—		59	—	
Finance and interest income - economic interests	**—**	**(76)**		—	(171)		—	(86)	
Adjusted FFO - economic interests	**—**	**146**		—	162		—	137	
Other	**5**	**—**		4	—		5	—	
FFO	**757**	**378**	**379**	927	381	546	804	358	446
Dividend from TransAlta Renewables			**151**			151			140
Distributions to TA Cogen's Partner			**(37)**			(86)			(86)
Less: PPA Termination Payments			**(56)**			(157)			—
Deconsolidated TransAlta FFO			**437**			454			500

Financial Position

The following chart highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2018, to Dec. 31, 2019:

Assets	Increase/ (decrease)	Primary factors explaining change
Cash and cash equivalents	322	Timing of receipts and payments and cash received from the issuance of the exchangeable securities
Restricted cash	(34)	Kent Hills restricted cash was released in July 2019 ($31 million) and the restricted cash related to the TransAlta OCP bonds was paid in Feb. 2019 ($35 million), partially offset by the Off Coal Agreement payments received ($17 million) in Aug. 2019 that will be restricted until the TransAlta OCP bonds are paid in Feb. 2020 as well as new restricted cash related to the Big Level tax equity financing ($15 million)
Trade and other receivables	(294)	Timing of customer receipts
Finance lease receivables (long-term)	(15)	Principal repayments
PP&E	43	Depreciation for the period ($630 million), net disposals mainly related to the Genesee 3 sale and decommissioning of Mississauga ($265 million), unfavourable changes in foreign exchange rates ($58 million), and adjustments on implementation of IFRS 16 ($62 million), partially offset by additions ($522 million), acquisitions mainly related to Keephills 3 and Antrim ($439 million) and revisions to decommissioning and restoration costs ($23 million)
Right of use assets	146	Transfers from PP&E, intangible assets and other assets ($38 million) and new right of use assets recognized under IFRS 16 ($47 million) (see Accounting Changes section for further details), additions related to the Pioneer Pipeline ($45 million) as well as land lease and other additions ($36 million), partially offset by depreciation ($18 million)
Intangible assets	(55)	Amortization ($50 million) and net disposals mainly related to the Genesee 3 sale ($28 million), partially offset by additions ($14 million) and acquisitions mainly related to Antrim ($16 million)
Other assets	(36)	Pioneer Pipeline project development costs were reclassified to PP&E ($15 million) and the write-off of projects that will no longer proceed ($18 million)
Other	3	
Total change in assets	**80**	

Liabilities and equity	Increase/ (decrease)	Primary factors explaining change
Accounts payable and accrued liabilities	(83)	Timing of payments and accruals
Dividends payable	(21)	Timing of the declaration of common and preferred share dividends
Credit facilities, long-term debt and lease obligations (including current portion)	(55)	Repayments on the credit facilities ($119 million), repayments of long-term debt ($96 million) favourable changes in foreign exchange ($42 million), reduction due to the tax shield on tax equity financing ($35 million), derecognition of a lease obligation on implementation of IFRS 16 ($32 million) and repayments of lease obligations ($21 million) were partially offset by the issuance of the tax equity financing ($166 million) and new lease liabilities ($133 million)
Exchangeable securities	326	Issuance of exchangeable debentures in May 2019 to Brookfield. See the Significant and Subsequent Events section of this MD&A for further details
Decommissioning and other provisions (current and long-term)	90	Change in estimate for the Centralia mine ($141 million), accretion ($23 million), acquisition of liabilities ($19 million), revisions to discount rates ($16 million) and liabilities incurred ($14 million), partially offset by liabilities settled ($42 million), lower estimated cash flows at other locations ($38 million), disposition of liabilities ($32 million) and favourable changes in foreign exchange rates ($7 million). See the Accounting Changes section of this MD&A for further details
Risk management liabilities (current and long-term)	(21)	Contract settlements, partially offset by favourable market prices
Contract liabilities	(73)	The coal rights contract was terminated as part of the Keephills 3 and Genesee 3 swap ($88 million), partially offset by contract liabilities moved from defined benefit obligation and other long-term liabilities as they are no longer considered leases on the adoption of IFRS 16 ($15 million) (see the Significant and Subsequent Events and Accounting Changes sections of this MD&A for further details)
Defined benefit obligation and other long-term liabilities	14	Actuarial losses before tax ($33 million) partially offset by liabilities moved to contract liabilities ($15 million)
Deferred income tax liabilities	(29)	Decrease in taxable temporary differences mainly due to the Alberta tax rate reduction (see the Other Consolidated Analysis section for further details)
Equity attributable to shareholders	(36)	Net other comprehensive loss ($28 million), common share dividends ($34 million), preferred share dividends ($30 million), shares purchased under NCIB ($68 million), partially offset by net earnings ($82 million), the effect of share-based payment plans ($33 million) and changes in non-controlling interests in TransAlta Renewables ($6 million)
Non-controlling interests	(36)	Distributions paid and payable ($135 million) and intercompany fair value through other comprehensive income investments ($17 million), partially offset by net earnings ($94 million), changes in non-controlling interests in TransAlta Renewables from share issuances under the dividend reinvestment plan ($22 million)
Other	4	
Total change in liabilities and equity	**80**	

Cash Flows

The following chart highlights significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2018, and Dec. 31, 2017, compared to the year ended Dec. 31, 2019:

Year ended Dec. 31	**2019**	2018	**Increase/ (decrease)**	**Primary factors explaining change**
Cash and cash equivalents, beginning of year	**89**	314	(225)	
Provided by (used in):				
Operating activities	**849**	820	29	Favourable changes in non-cash working capital ($165 million), partially offset by lower cash flow from operations before changes in working capital ($136 million) mainly due to the net impact of the PPA Termination Payments
Investing activities	**(512)**	(394)	(118)	Higher additions to PP&E mainly as a result of the construction of Big Level and Antrim ($140 million), higher acquisitions mainly due to the Kineticor acquisition ($87 million), investment in the Pioneer Pipeline ($83 million), lower scheduled payments from finance lease receivables ($35 million), partially offset by a decrease in restricted cash ($69 million), a favourable change in non-cash investing working capital ($128 million) and higher cash proceeds on sale of PP&E ($11 million)
Financing activities	**(14)**	(651)	637	Lower repayments of long-term debt ($1,083 million), issuance of the exchangeable securities ($350 million), lower proceeds on issuance of debt ($179 million) and lower distributions paid to subsidiaries' non-controlling interests ($59 million), partially offset by higher net repayments under credit facilities ($431 million), proceeds received in 2018 for the sale of TransAlta Renewables common shares ($144 million), lower realized gains on financial instruments ($48 million) and higher share buybacks under NCIB ($45 million)
Translation of foreign currency cash	**(1)**	—	(1)	
Cash and cash equivalents, end of year	**411**	89	322	

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 the 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 PP&E ($61 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)	

Financial Capital

The Corporation is focused on strengthening our financial position and cash flow coverage ratios to ensure a strong balance sheet is maintained and sufficient financial capital is available. 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. Maintaining a strong balance sheet also allows our 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.

In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised their rating outlook to stable from positive. During 2019, Fitch Ratings lowered the Corporation's Unsecured Debt rating and Issuer Rating to BB+ 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 lowered the Corporation's Unsecured Debt rating and Issuer Rating to BB+ with a stable outlook. Risks associated with our credit ratings are discussed in the Governance and Risk Management section of this MD&A.

Capital Structure

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

As at Dec. 31	2019		2018		2017	
	$	**%**	$	%	$	%
TransAlta Corporation						
Recourse debt - CAD debentures	**647**	**9**	647	9	1,046	13
Recourse debt - US senior notes	**905**	**13**	943	13	1,499	19
Exchangeable securities	**326**	**5**	—	—	—	—
Credit facilities	**—**	**—**	174	2	—	—
Other	**9**	**—**	11	—	13	—
Less: cash and cash equivalents	**(348)**	**(5)**	(16)	—	(294)	(4)
Less: principal portion of restricted cash on TransAlta OCP	**(10)**	**—**	(27)	—	—	—
Less: fair value asset of economic hedging instruments on debt[1]	**(7)**	**—**	(10)	—	(30)	—
Net recourse debt, excluding US tax equity financing	**1,522**	**22**	1,722	24	2,234	28
US tax equity financing	**145**	**2**	28	—	31	—
Non-recourse debt	**426**	**6**	469	6	208	3
Lease obligations	**119**	**2**	63	1	69	1
Total net debt - TransAlta Corporation	**2,212**	**32**	2,282	31	2,542	32
TransAlta Renewables						
Credit facility	**220**	**3**	165	2	27	—
Less: cash and cash equivalents	**(63)**	**(1)**	(73)	(1)	(20)	—
Net recourse debt	**157**	**2**	92	1	7	—
Non-recourse debt	**718**	**10**	767	11	814	11
Lease obligations	**23**	**—**	—	—	—	—
Total net debt - TransAlta Renewables	**898**	**12**	859	12	821	11
Total consolidated net debt	**3,110**	**44**	3,141	43	3,363	43
Non-controlling interests	**1,101**	**15**	1,137	16	1,059	14
Equity attributable to shareholders						
Common shares	**2,978**	**42**	3,059	42	3,094	40
Preferred shares	**942**	**13**	942	13	942	12
Contributed surplus, deficit and accumulated other comprehensive income	**(959)**	**(14)**	(1,004)	(14)	(710)	(9)
Total capital	**7,172**	**100**	7,275	100	7,748	100

(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.

We continued strengthening our financial position during 2019 and have reduced our total consolidated net debt by $253 million since the end of 2017. Our financing strategy includes replacing our senior recourse debt with asset-level financing, including tax equity. Net recourse debt at TransAlta, excluding tax equity financing, declined by $712 million from $2,234 million in 2017 to $1,522 million in 2019. We have enhanced shareholder value by:

2019

- Obtaining US$126 million in tax equity financing to fund the Big Level and Antrim wind facilities;
- Entering into a strategic investment with Brookfield whereby Brookfield agreed to invest $750 million in the Corporation. On May 1, 2019, we received the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039, which are exchangeable by Brookfield into an equity ownership interest in our Alberta Hydro Assets in the future. The remaining $400 million will be invested in Oct. 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met;
- Purchasing and cancelling 7,716,300 common shares at an average price of $8.80 per share through our NCIB program, for a total cost of $68 million;

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 outstanding non-recourse debentures.

Between 2020 and 2022, we have approximately $1,217 million of debt maturing, comprised of approximately $920 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022.

The weakening of the US dollar has decreased our long-term debt balances by $42 million as at Dec. 31, 2019. 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	**2019**	2018
Effects of foreign exchange on carrying amounts of US operations (net investment hedge) and finance lease receivable	**(21)**	42
Foreign currency cash flow hedges on debt	**(9)**	11
Economic hedges and other	**(9)**	21
Unhedged	**(3)**	2
Total	**(42)**	76

Our credit facilities provide us with significant liquidity. At Dec. 31, 2019, we had $2.2 billion (2018 - $2.0 billion) of committed credit facilities, of which $1.3 billion (2018 - $0.9 billion) was available for use. We are in compliance with the terms of the credit facilities. At Dec. 31, 2019, the $0.9 billion (2018 - $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $0.2 billion (2018 - $0.3 billion) and letters of credit of $0.7 billion (2018 - $0.7 billion). These facilities are comprised of a $1.3 billion committed syndicated bank facility expiring in 2023, TransAlta Renewables $700 million committed syndicated bank credit facility expiring in 2023, and three bilateral credit facilities, totalling $240 million, expiring in 2021.

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, Kent Hills Wind LP and TransAlta OCP non-recourse bonds with a carrying value of $1,143 million (Dec. 31, 2018 - $1,235 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2019. 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 2020. At Dec. 31, 2019, $42 million (Dec. 31, 2018 -$33 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, 2019.

Proceeds received from the Big Level and Antrim tax equity financing in the amount of $91 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying outstanding project development costs.

Working Capital

Including the current portion of long-term debt and lease obligations, the excess of current assets over current liabilities was $224 million as at Dec. 31, 2019 (2018 - $432 million). Our working capital decreased year over year mainly due to the $400 million debenture payable in 2020. Excluding the current portion of long-term debt and lease obligations of $513 million, the excess of current assets over liabilities was $737 million as at Dec. 31, 2019 (2018 - $580 million), an increase of $157 million, mainly due to higher cash and cash equivalents and repayments on the credit facility as a result of receiving the $350 million exchangeable debentures issued in May 2019 to Brookfield, as well as strong cash flow from operating activities.

Share Capital

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 Cumulative Redeemable Rate Reset Preferred Shares also failed to receive the required number of minimum votes in 2019 to give effect to conversions into Series H. Therefore, the Series G Preferred Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board.

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

As at	Mar. 3, 2020	Dec. 31, 2019	Dec. 31, 2018
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	**277.0**	**277.0**	284.6
Preferred shares			
Series A	10.2	**10.2**	10.2
Series B	1.8	**1.8**	1.8
Series C	11.0	**11.0**	11.0
Series E	9.0	**9.0**	9.0
Series G	6.6	**6.6**	6.6
Preferred shares issued and outstanding, end of period	**38.6**	**38.6**	38.6

Non-Controlling Interests

As of Dec. 31, 2019, we own 60.4 per cent (2018 – 60.9 per cent) of TransAlta Renewables. In 2019, our ownership percent decreased due to TransAlta Renewables issuing approximately two million common shares under their Dividend Reinvestment Plan ("DRIP"). We do not participate in this plan.

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 also own 50.01 per cent of TA Cogen, which owns, operates or has an interest in four natural-gas-fired facilities (Mississauga, Ottawa, Windsor and Fort Saskatchewan) and one coal-fired generating facility. Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those assets.

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2019, decreased by $14 million to $94 million compared to 2018. Earnings were down at TransAlta Renewables in 2019 mainly due to lower finance and interest income from subsidiaries of TransAlta, foreign exchange losses due to the weakening of the Australian dollar and higher depreciation expense, partially offset by an increase in the fair value of investments in subsidiaries of TransAlta. Earnings from TA Cogen were higher in 2019 mainly due to strong Alberta pricing and lower costs of fuel at the coal-fired generating facility.

Reported earnings attributable to non-controlling interests for the year ended Dec. 31, 2018, increased by $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.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2019	2018	2017
Interest on debt	**161**	184	218
Interest on exchangeable securities	**20**	—	—
Interest income	**(13)**	(11)	(7)
Capitalized interest	**(6)**	(2)	(9)
Loss on redemption of bonds	**—**	24	6
Interest on finance lease obligations	**4**	3	3
Credit facility fees, bank charges, and other interest	**15**	13	18
Tax shield on tax equity financing	**(35)**	—	—
Other(1)	**10**	15	(3)
Accretion of provisions	**23**	24	21
Net interest expense	**179**	250	247

(1) In 2019, other interest expense included approximately $5 million (2018 - $7 million, 2017 - nil) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable.

Net interest expense was lower in 2019 primarily due to the $35 million credit related to the tax shield (tax benefit on tax depreciation) claimed in 2019 on the Big Level and Antrim projects and allocated to the tax equity investor. In addition, there were no prepayment premiums in 2019 as there were no early redemptions of bonds during the year, compared to 2018, which included $24 million in prepayment premiums.

Net interest expense was higher in 2018 compared to 2017, 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. These increases were partially offset by lower interest on debt as a result of lower debt levels.

Dividends to Shareholders

The declaration of dividends is at the discretion of the Board. The following are the common and preferred shares dividends declared each quarter during 2019 and the first quarter of 2020:

	Payable date		Common dividends	Preferred Series dividends per share				
Declaration date	**Common shares**	**Preferred shares**	**per share**	**A**	**B**	**C**	**E**	**G**
Apr 15, 2019	Jul 1, 2019	Jun 30, 2019	0.0400	0.16931	0.23136	0.25169	0.32463	0.33125
Jul 16, 2019	Oct. 1, 2019	Sept. 30, 2019	0.0400	0.16931	0.23422	0.25169	0.32463	0.33125
Oct. 9, 2019	Jan. 1, 2020	Dec. 31, 2019	0.0400	0.16931	0.23113	0.25169	0.32463	0.31175
Jan. 16, 2020	Apr 1, 2020	Mar 31, 2020	0.0425	0.16931	0.22949	0.25169	0.32463	0.31175

2020 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2020 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	Target
Comparable EBITDA	$925 million to $1,000 million
FCF	$325 million to $375 million
Dividend	$0.17 per share annualized

Range of key power price assumptions

Market	Power Prices ($/MWh)
Alberta Spot	$53 to $63
Mid-C Spot (US$)	$25 to $35

Other assumptions relevant to the 2020 financial outlook	
Sustaining capital	$170 million to $200 million

Operations

Market Pricing and Hedging Strategy

For 2020, power prices in Alberta are expected to be comparable to 2019 given similar overall supply and demand conditions; however, weather and demand are major factors in actual settled prices. Pacific Northwest power prices for 2020 are expected to be lower than 2019 as 2019 prices were impacted by specific events in the first quarter that are not expected to occur in the future. Ontario power prices are expected to be comparable or higher than 2019 prices.

The objective of our portfolio management strategy is to deliver a high confidence for annual FCF that 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

For the Alberta thermal fleet, we expect the 2020 cash fuel costs per tonne of coal to be higher than the 2019 costs as mine volumes are declining, resulting in slightly less mine cost efficiency. Coal volumes are declining as a result of increased gas consumption in the Alberta thermal fleet. This change in fuel mix will drive lower GHG emissions and the combined effect will result in lower total fuel and GHG costs for a given volume of power production.

In the Pacific Northwest of the US, the coal mine adjacent to our Centralia 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 rail freight costs fluctuate partly with gas prices. The delivered fuel cost in 2020 is expected to be consistent with 2019 costs.

Most of the generation from gas turbine-based power plants is sold under contracts with passthrough provisions for fuel. For gas generation with no passthrough 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 2020 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

Interest expense for 2020 is expected to be higher than in 2019 largely due to higher levels of debt. The increase in debt is mainly due to expected drawings on our credit facilities as we execute on our growth plans as well as the exchangeable debentures issued in May 2019 to Brookfield and the $400 million exchangeable preferred shares, which are expected to be issued to Brookfield in October 2020. In addition, changes in interest rates on variable debt, and in the value of the Canadian dollar relative to the US dollar can affect the amount of interest expense incurred.

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities. We currently have access to $1.7 billion in liquidity including $411 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 and 2022. Refer to the Corporate Strategy and Financial Capital sections of this MD&A for further details.

Sustaining and Productivity Capital Expenditures

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

Category	Description	Spent in 2018	Spent in 2019	Expected spend in 2020
Routine capital[1]	Capital required to maintain our existing generating capacity	50	**50**	60 - 80
Planned major maintenance	Regularly scheduled major maintenance	58	**68**	100 - 110
Mine capital	Capital related to mining equipment and land purchases	42	**23**	10 - 10
Total sustaining capital[2]		150	**141**	**170 - 200**
Insurance recoveries of sustaining capital expenditures	Insurance proceeds - 2019 relates to the tower fires at Wyoming Wind and Summerview	(7)	**(10)**	— - —
Total sustaining capital		143	**131**	**170 - 200**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	21	**9**	10 - 15
Total sustaining and productivity capital		164	**140**	**180 - 215**

(1) Includes hydro life extension expenditures.
(2) On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. Refer to the Accounting Changes section of this MD&A for further details.

Significant planned major outages at TransAlta's operated units for 2020 include the following:

- One outage for major maintenance at Sundance Unit 6 within our Canadian Coal segment during the third and fourth quarters of 2020. This work will be undertaken in parallel with the coal-to-gas conversion of this unit;
- Distributed planned maintenance expenditures across the entire hydro fleet; and
- Distributed expenditures across our wind fleet, focusing on planned component replacements.

There is also one major planned outage at one of our non-operated units in 2020:

- An outage for major maintenance at Sheerness Unit 2 during the first quarter of 2020. This work will be undertaken in parallel with the coal-to-gas conversion of this unit.

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 2020:

	Coal	Gas and renewables	Total
GWh lost	700 - 800	450 - 500	1,150 - 1,300

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 $1.7 billion in liquidity, if required. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment.

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.

Competitive Forces

Supply and demand 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.

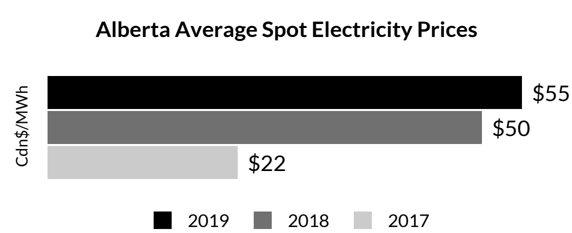
Renewable capacity addition has been strong for the past several years due to government incentives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable electricity as well as natural-gas-fired generation. This expectation is driven by the low 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 US and Australia. Our target customers in this area are incumbent utility providers and large industrial and mining operators.

Alberta

Approximately 57 per cent of our gross installed capacity is located in Alberta and approximately 42 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 third quarter of 2019, we announced our Clean Energy Investment Plan, which includes converting our existing Alberta coal assets to natural gas, which will position TransAlta's fleet as a low-cost generator in Alberta. See further details in the Corporate Strategy section of this MD&A.

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 electricity and Ancillary Services in excess of obligations on our Hydro Alberta PPAs. 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 was flat from 2018 to 2019. The average pool price increased from $50.29/MWh in 2018 to $54.88/MWh in 2019. The majority of the pool price increase was due to higher settled prices during the first quarter of 2019. The higher prices also positively impacted our merchant wind and hydro portfolio.

Our market share of offer control in Alberta in 2019 was approximately 21 per cent (16 per cent if the Sundance mothballed units are excluded from offer control).

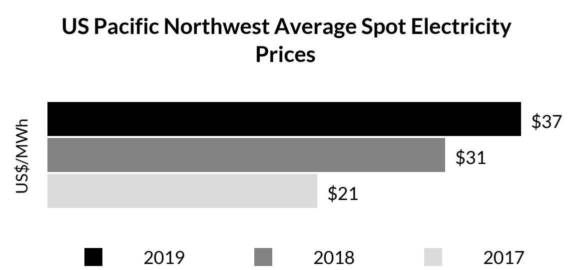
In late November 2016, we announced that we entered into an Off Coal Agreement with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method other than the combustion of coal.

We expect additional compliance costs as a result of the Canadian federal government's *Greenhouse Gas Pollution Pricing Act*, which sets a national price on GHG emissions and 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 B and C PPAs, effective Mar. 31, 2018. As of Apr. 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.

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 an emphasis on energy efficiency.



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 US, 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 and the US along with acquisitions in markets in which we have existing operations. We maintain highly qualified and experienced development teams to identify and develop these opportunities. In co-generation, we are working with customers to evaluate behind-the-fence solutions.

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.

Power-Generating Portfolio Capital

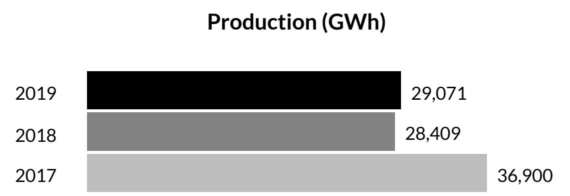
We monitor availability closely as a key metric to achieving our financial targets. We adjust our maintenance and sustaining capital expenditures to optimize financial returns on our investments and to align with our strategic intentions.

Availability and Production

Our availability target for our Canadian Coal fleet was 87 to 89 per cent for 2019. We achieved 89 per cent (2018 - 93 per cent, 2017 - 82 per cent) availability in Canadian Coal. Our availability target for our other generating assets (gas and renewables) was in the range of 92 to 96 per cent in 2019. Both Canadian Gas and Wind and Solar achieved the higher end of this range. Canadian Gas achieved 95 per cent (2018 - 93 per cent, 2017 - 92 per cent) and Wind and Solar achieved 95 per cent (2018 - 95 per cent, 2017 - 96 per cent). As a result of unplanned outages, Australian Gas achieved 91 per cent (2018 - 94 per cent, 2017 - 93 per cent), slightly less than the target.

Our availability for the entire fleet in 2019, after adjusting for dispatch optimization at US Coal, was 90 per cent (2018 - 91 per cent, 2017 - 87 per cent) and was slightly lower than last year. Higher planned outages at Canadian Coal, forced outages and derates at US Coal and unplanned outages at Australian Gas, were partially offset by lower planned outages at Canadian Gas.

Production for the year ended Dec. 31, 2019, increased 662 GWh compared to 2018. The increase was mainly at US Coal where production increased 1,787 GWh due to higher merchant pricing in the first half of 2019 and timing of dispatch optimization. This was partially offset by Canadian Coal where production decreased 1,381 GWh primarily due to the mothballing and retirement of certain Sundance units as well as planned outages, partially offset by lower unplanned outages.



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.

Year ended Dec. 31	2019	2018	2017
Routine capital	**50**	50	69
Mine capital	**23**	42	28
Planned major maintenance	**68**	58	121
Total sustaining capital expenditures(1)	**141**	150	218
Productivity capital	**9**	21	24
Total sustaining and productivity capital expenditures(1)	**150**	171	242
Insurance recoveries of sustaining capital expenditures	**(10)**	(7)	—
Net amount	**140**	164	242

(1) On implementation of IFRS 16, we reclassified payments on finance leases out of sustaining capital and now show this spend as a separate line to calculate FCF and segmented cash flow. See the Accounting Changes section of this MD&A for further details.

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

Year ended Dec. 31	2019	2018	2017
GWh lost(1)	**935**	381	1,234

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

Total sustaining capital expenditures were $9 million lower compared to 2018 and total productivity capital was $12 million lower in 2019 compared to 2018. The productivity capital expenditures relate to the funding of some Greenlight transformation initiatives. Refer to the Corporate Strategy section of this MD&A for further details on our Greenlight program. In certain cases, payback is expected to be achieved within three years. We also completed planned major outages at Keephills Unit 1, Sundance Unit 4 and Sarnia.

Other Consolidated Analysis

Asset Impairment Charges and Reversals

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

2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia Plant CGU exceeded the carrying value, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	2016
Mid-Columbia annual average power prices	**US$30 to US$42 per MWh**	US$22 to US$46 per MWh
On-highway diesel fuel on coal shipments	**US$2.35 to US$2.40 per gallon**	US$1.69 to US$2.09 per gallon
Discount rates	**5.2 to 6.4 per cent**	5.4 to 5.7 per cent

During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings. Refer to Note 3 and 22 of the consolidated financial statements for further details.

Assets Held for Sale

In the fourth quarter of 2019, the Corporation identified several trucks and associated inventory to be sold within the Canadian Coal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

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. 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 seven 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. 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.

Project Development Costs

During 2019, the Corporation wrote off $18 million (2018 - $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, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2019, we provided letters of credit totalling $690 million (2018 - $720 million) and cash collateral of $42 million (2018 - $105 million). These letters of credit and cash collateral secure certain amounts included on our Consolidated Statements of Financial Position under risk management liabilities, defined benefit obligation and other long-term liabilities and decommissioning and other provisions.

Commitments

Contractual commitments are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas, transportation and other contracts	125	125	120	128	131	1,493	**2,122**
Transmission	9	5	4	3	—	—	**21**
Coal supply and mining agreements[1]	147	16	16	16	8	14	**217**
Long-term service agreements	50	22	32	17	15	14	**150**
Non-cancellable operating leases[2]	4	2	2	2	3	64	**77**
Long-term debt[3]	494	98	625	372	105	1,410	**3,104**
Exchangeable securities[4]	—	—	—	—	—	350	**350**
Principal payments on lease obligations	19	14	9	6	4	90	**142**
Interest on long-term debt and lease obligations[5,6]	161	138	128	98	87	671	**1,283**
Interest on exchangeable securities[4,6]	25	25	25	24	24	—	**123**
Growth	535	254	196	270	13	—	**1,268**
TransAlta Energy Transition Bill	6	6	6	6	—	—	**24**
Total	**1,575**	**705**	**1,163**	**942**	**390**	**4,106**	**8,881**

(1) Commitments related to Sheerness may be impacted by the cessation of coal-fired emissions on or before Dec. 31, 2030.
(2) Includes leases that have not yet commenced.
(3) Excludes impact of derivatives.
(4) Assumes the exchangeable debentures will be exchanged by Brookfield on Jan. 1, 2025. Refer to the Significant and Subsequent Events section of this MD&A for further details.
(5) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.
(6) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

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 Centralia 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. At Dec. 31, 2019, the Corporation has funded approximately US$37 million of the commitment.

Contingencies

Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding before the Alberta Utilities Commission. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016 and issue a single invoice charging or crediting market participants for the difference in losses charges. A more recent decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was to be issued in April 2021, with cash settlement expected in June 2021. The current total estimate of exposure based on known data is approximately $12 million. However, the AESO recently requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, resulting in invoices being issued as early as April 2020 for settlement in June 2020, a year earlier than anticipated. The Corporation is challenging this request.

FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first dispute arose as a result of FMG's attempted termination of the South Hedland PPA on the basis that the conditions to establishing commercial operation under the South Hedland PPA had not been met. TransAlta's view is that all conditions to establishing commercial operation under the terms of the South Hedland PPA had been satisfied in full. TransAlta initiated legal action against 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. This matter is scheduled to proceed to trial beginning June 15, 2020.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

Mangrove Claim
On Apr. 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming the Corporation, the incumbent members of the Board of Directors of TransAlta on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is alleging, among other things, oppression by the Corporation and the named directors and is seeking to set aside the 2019 Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020.

Keephills 1 Superheater
Keephills Unit 1 was taken offline from Mar. 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool is attempting to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. TransAlta denied the Balancing Pool had the right to do so. The Alberta Court of Queen's Bench confirmed the Balancing Pool has a right under the PPA to commence an arbitration, independent of the PPA buyer. On Sept. 4, 2019, the Alberta Court of Appeal upheld the lower court's decision. TransAlta sought permission to appeal the Alberta Court of Appeal's decision to the Supreme Court of Canada. The application was denied and the matter will now proceed to arbitration, with a hearing potentially sometime in 2020.

Sundance A Decommissioning
TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the mine. The Balancing Pool filed a statement of intent to participate as an intervener because it disagrees that, amongst other things, the mine decommissioning costs should be included. TransAlta anticipates it will receive payment from the Balancing Pool in 2020 for its decommissioning costs; however, the amount is uncertain.

Hydro PPA Renewable Energy Credits
The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $27 million, earned by the Hydro plants under the *Carbon Competitiveness Incentive Regulation* ("CCIR") in 2018 and 2019. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. We anticipate this dispute will be resolved by the end of 2021.

Direct Assigned Capital Deferral Account Application
AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 direct assigned capital deferral account for the Edmonton region: 240 kV line upgrades project (the "Proceeding"). TransAlta is a secondary applicant in the Proceeding. Altalink and TransAlta seek to have their costs approved by the AUC as reasonable and prudent. The Enoch Cree Nation ("ECN") and the Consumers Coalition of Alberta are registered participants in the Proceeding. Currently Altalink, ECN and TransAlta's interests are closely aligned. TransAlta believes it has a reasonable chance of having its costs (estimated at about $21 million) approved.

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 of the 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, other provisions and joint arrangements. 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, Finance and Risk Committee ("AFRC") and our independent auditors. The AFRC 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

In 2018, the Corporation adopted IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"). Comparative information prior to 2018 was not restated and is reported under IAS 18 *Revenue*. The Corporation's accounting policies for the current and prior periods for revenue recognition are outlined in Note 2 of the 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, environmental 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 that 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 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 at the measurement date. 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 interpolation formulas, where the inputs are readily observable.

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 mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be 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 price relationships. 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, 2019, is an estimated total upside of $79 million (2018 - $149 million upside) and total downside of $172 million (2018 - $149 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $46 million upside (2018 - $116 million upside) and $139 million downside (2018 - $116 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$28 (Dec. 31, 2018 - US$20-US$35) for the period from 2020 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.

In addition to the Level III fair value measurements discussed above, the Brookfield Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum of 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the option to exchange is considered a Level III fair value measurement, with an estimated upside of $35 million and downside of $27 million potential impact to the carrying value of nil as at Dec. 31, 2019. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that PP&E and finite life intangible assets are impaired or whether a previously recognized impairment may no longer exist or may have decreased. 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 asset or CGU to which the asset 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, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. 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 2019.

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 2019 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Refer to the Other Consolidated Analysis section of this MD&A for further details.

Project Development Costs

Project development costs include external, direct and incremental costs that are necessary for completing an acquisition or construction project. These costs are recognized 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 other assets. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

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 2019, total depreciation and amortization expense was $709 million (2018 - $710 million, 2017 - $708 million), of which $119 million (2018 - $136 million, 2017 - $73 million) relates to mining equipment and is included in fuel, carbon compliance and purchased power.

As a result of the Clean Energy Investment Plan described in the Corporate Strategy section of this MD&A, we will convert our existing Alberta coal assets to natural gas and therefore the useful lives of the PP&E and amortizable intangibles associated with some of our Alberta coal assets were updated to reflect these changes. For certain Wind and Solar PP&E we identified additional components for parts with shorter useful lives than originally estimated and revised the useful lives accordingly. 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.

For purposes of the 2019, 2018 and 2017 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 our contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where we are a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with us, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact 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 amount of certain items of revenue and expense are 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 (temporary differences). A deferred income tax asset may also be recognized for the benefit expected from unused tax credits and losses available for carryforward, to the extent that it is probable that future taxable earnings will be available against which the tax credits and losses can be applied.

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 income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that 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.

A net deferred income tax liability of $454 million (2018 - $473 million) has been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2019. This primarily relates to income tax deductions in excess of related depreciation of PP&E of $828 million (2018 - $896 million), taxes on unrealized gains from risk management transactions of $141 million (2018 - $145 million), partially offset by temporary differences related to future decommissioning and restoration costs of $122 million (2018 - $113 million) and net operating loss carryforwards of $252 million (2018 - $281 million). We believe there will be sufficient taxable income that will permit the use of these loss carryforwards in the tax jurisdictions where they exist. Additional US tax losses are available for use for which no deferred income tax assets have been recognized.

Employee Future Benefits

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

The liabilities for pension, other post-employment 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 generating facilities and mine sites in the period in which they are incurred if there is a legal or constructive obligation to remove the facilities and restore the 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 current market-based risk-free interest rate adjusted to reflect the market's evaluation of our credit standing.

As at Dec. 31, 2019, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position were $501 million (2018 - $407 million). During 2019, we adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. Refer to the Accounting Changes section of this MD&A for further details. In addition, as a result of the changes in estimated useful lives, described in the Accounting Changes section, the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed due to the change in useful life. The use of a lower inflation rate decreased the corresponding liabilities.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.3 billion, which will be incurred between 2020 and 2073. The majority of these costs will be incurred between 2020 and 2050.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	5
Undiscounted decommissioning and restoration provision	10	3

Other Provisions

Where necessary, we recognize provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using 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.

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, which classification affects the accounting for the joint arrangement. In making this classification, the Corporation exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

Accounting Changes

Current Accounting Changes

IFRS 16 *Leases*

We adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases.

We elected to apply the modified retrospective method of transition. Under this method, the comparative periods presented in the consolidated financial statements were not restated, and comparative period leases continue to be reported as recognized following IAS 17 *Leases* or International Financial Reporting Interpretations Committee Interpretation 4 *Determining Whether an Arrangement Contains a Lease*. Instead of restating prior years' results, we recognized the cumulative impact of the initial application of the standard of $3 million in deficit as at Jan. 1, 2019.

Impact on the financial statements

Lessee

We recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease obligation measured at the present value of the remaining lease payments discounted using our incremental borrowing rate (or the rate implicit in the lease) applied to the lease obligations at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease obligations on Jan. 1, 2019, was 5.71 per cent. On Jan. 1, 2019, we recognized $83 million in lease obligations, comprised of $52 million of new lease obligations and $31 million (net of $32 million derecognized) that were previously shown as finance lease obligations.

The associated right of use assets were measured at an amount equal to the lease obligation, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, we recognized right of use assets of $85 million, including $38 million that was previously included in PP&E, intangible assets and other assets.

Applying the IFRS 16 definition of a lease 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, resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in deficit.

Lessor

Several of the Corporation's long-term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these are now accounted for by applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

Note 2 and Note 3 of the consolidated financial statements include a more detailed discussion of our accounting policies under IFRS 16 and our adoption of IFRS 16, respectively.

Change in Estimates

Canadian Coal

As a result of the Clean Energy Investment Plan described in the Corporate Strategy section of this MD&A, we adjusted the useful lives of certain coal assets, effective Sept. 1, 2019. Assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined-cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019, increased by approximately $16 million.

Wind and Solar

During 2019, the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. Accordingly, depreciation expense for the year ended Dec. 31, 2019, increased by approximately $11 million.

Sheerness

In 2019, we adjusted the useful life of the Sheerness coal-fired plant assets to align with the dual-fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the year ended Dec. 31, 2019, decreased by approximately $8 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia

In 2019, we adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

For further details and changes in estimates relating to prior years, refer to the Other Consolidated Analysis section of this MD&A and Note 3 of the consolidated financial statements.

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.

Hedge accounting follows a principles-based approach for qualifying hedges, which is aligned with an entity's approach to risk management. 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, 2019, Level III instruments had a net asset carrying value of $686 million (2018 - $695 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, 2018.

Environment, Social and Governance ("ESG")

The Corporation places high priority on ESG or sustainability management and performance. We have reported on sustainability for over 25 years and fiscal 2019 reporting marked our fifth year of integrating financial and sustainability disclosure.

In total, we own 73 power-generating facilities across Australia, Canada and the US. We are invested in a mix of wind, solar, hydro, natural gas and coal assets for a total of approximately 8,000 MW of gross generating capacity. The following outlines material environmental and social considerations in respect of our operated facilities.

ESG at TransAlta - Environment, Social and Governance Objectives

Sustainability is a core value for the Corporation. For TransAlta, it means integrating actions into our current plans that recognize the long-term impacts of our operations on the environment and society. Our programs also ensure that we work with stakeholders in the community and use leading governance practices in our decision-making processes. We believe that integrating the three pillars of environment, social and governance is important to the long-term decisions we make for the benefit of all our stakeholders.

Our coal-to-gas conversion strategy and pursuit of strategic growth opportunities in clean electricity (renewable and natural gas) generation highlights one element of our environment pillar. By 2025 our generation portfolio will be comprised entirely of renewable and natural gas assets. Natural gas is a clean fuel that plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. Our focus on clean electricity generation also mitigates the impact of potential adverse regulatory developments in response to emerging environmental regulation including, but not limited to, a regulated cost of carbon.

Environmental and Social Risk and Materiality

Our major environmental risk factors include weather, environmental disasters, climate change, exposure to the elements, environmental compliance risk, and current and emerging environmental regulation. Our major social risk factors include public health and safety, employee and contractor health and safety, local communities, employee retention, reputation management, and stakeholder relationships. Further guidance on our risk factors can be found in the Risk Management section of this MD&A.

Reporting Structure

Key elements of the following disclosure are guided by our sustainability materiality assessment. To help inform discussion and provide context on how ESG affects our business, we have applied components of leading ESG reporting frameworks, including Global Reporting Index, Sustainability Accounting Standards Board ("SASB") and Task Force on Climate-related Financial Disclosures ("TCFD"). Our content is structured according to guidance on non-traditional capitals from the International Integrated Reporting Framework.

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 of Dec. 31, 2019, we had 1,543 (2018 - 1,883) active employees. This number has decreased by 18 per cent from 2018 levels, following a reduction in positions at our coal fleet aligned to changes in the plant portfolio and from multiple initiatives across the business that used technology to reduce costs and increase efficiency.

With approximately 45 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 employees to participate in collective bargaining.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our more than 100-year heritage. Our core values are safety, innovation, sustainability, respect and integrity. These five core values help provide clarity for our employees and guide our behaviour and decision making. They also provide a foundation for leadership, collaboration, community support, personal growth and work/life balance. Through corporate initiatives and support throughout all levels of leadership, we encourage our employees to maximize their potential.

Our six-level organizational structure helps facilitate effective pace and decision-making in our organization. Our business operates as a business-centric model, with Canadian Coal, US Coal, Canadian Gas, Australian Gas, Wind and Solar, and Hydro as our six generating segments. In addition, our Energy Marketing segment optimizes our asset fleet and trades electricity and other energy commodities. Our Corporate segment, including finance, legal, administrative, business development and investor relations functions, oversees our business and provides strategic alignment. The Corporation also includes a Shared Services division which oversees our information technology, supply chain, human resources, engineering and accounting functions. The consolidation and centralization of these functions has allowed us to streamline, standardize and where appropriate automate these functions while reducing costs and improving service delivery across the organization. Our operations portfolio is run by a single leadership team, which provides operational and financial synergies, enhancing our competitiveness.

TransAlta is committed to improving its internal work environment and the way that employees perceive their work and the Corporation. We track a broad number of factors to provide us insight into our progress and we use a third party to assist us in tracking our progress on an annual basis. We have made continual and notable improvements year over year and continue to target further improvements as we look forward.

Health and Safety

The safety of our people, communities and the environment is one of our core values. At TransAlta, we operate large and often complex facilities. The environments in which we work, including Canadian winters and the Australian outback, can add additional challenges to keeping our employees, contractors and visitors safe. Each year we invest significant resources into improving our safety performance, including positively enhancing our safety culture. At meetings of more than four people, we have a practice of starting the meeting with a "safety moment", which helps share key safety learnings across the Corporation.

TransAlta's management systems underpin the delivery of safe, reliable and competitive electricity to our customers and partners. Our Total Safety Management System (TSMS) is a combination of recognized best practices in process safety, risk management, asset management, occupational health, safety and environmental management. Since expanding our Occupational Health and Safety program in 2015 to encompass Total Safety, we have transitioned from development and implementation of this framework into continuous improvement, always striving to achieve our Target Zero vision to operate our business with zero unexpected asset failures and zero environmental, health and safety incidents.

In 2019, we continued to progress our safety culture transformation and have provided employees with behavioural safety training tools and capabilities to improve both their personal safety and that of their coworkers.

In 2017, we introduced the Total Injury Frequency (TIF) metric to track the total number of injuries including minor first aids, relative to exposure hours worked.

In 2019, we achieved a TIF of 1.12 compared to 1.91 in 2018. This decrease was a direct result of our back-to-basics approach with respect to safety. Specifically, in 2019, we focused on hazard identification (including audits and inspections), housekeeping and improved contractor management practices across the fleet.

In addition to TIF, we are also tracking Total Recordable Injury Frequency (TRIF). TRIF tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked. TRIF provides us with the opportunity to target and monitor our significant injuries. It is also an industry-recognized safety metric and allows us to compare and benchmark our safety performance to that of our peers. Our TRIF result for 2019 was 0.73 compared to 1.00 in 2018.

Safety at TransAlta (employees and contractors)	2019	2018	2017
Lost-time injuries	**5**	1	6
Medical aids	**7**	12	15
Restricted work injuries	**3**	12	16
First aids	**8**	23	67
Total TIF injuries	**23**	48	104
Exposure hours	**4,106,898**	5,014,804	6,073,419
Total Injury Frequency (TIF)	**1.12**	1.91	3.42
Total Recordable Injury Frequency (TRIF)	**0.73**	1.00	1.22

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 gender diversity in our business is evidenced by our female participation rates on both our executive team and Board. As of Dec. 31, 2019, women made up 50 per cent of our executive officer team and 33 per cent of our Board. These percentages are higher than our peers in Canada. Industry research highlights that the percentage of Board seats held by women from all disclosing Canadian TSX-listed companies in Canada is 18.1 per cent and the average percentage of women on executive teams is 16.9 per cent.

To further support female advancement, we have set targets to: (i) maintain equal pay for women in equivalent roles, (ii) achieve 50 per cent representation of women on our Board by 2030 and (iii) achieve 40 per cent representation of women among all employees by 2030. Currently, women employees represent 20 per cent of all employees.

In early 2020, TransAlta was one of 325 companies globally to be added to the Bloomberg Gender Equality Index. Inclusion in the index recognizes our comprehensive investment in workplace gender equality and our commitment to driving progress by developing inclusive policies and disclosing data using Bloomberg's gender reporting framework.

Employee Retirement Savings Programs

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 programs, which include various incentive plans designed to align performance with our annual and longer-term targets, as determined annually by the Board.

Retirement savings plans are an example of rewards we provide. We have registered pension plans in Canada and the US. 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 is an additional non-registered supplemental pension plan ("SPP") for members whose annual earnings exceed the Canadian income tax limit. The DB SPP was closed as of Dec. 31, 2015, and a new DC SPP commenced for only executive members hired after Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered in the DB SPP.

The Canadian and US DB pension plans are closed to new entrants, with the exception of the Highvale mine (SunHills) pension plan acquired in 2013. The US DB pension plan was frozen effective Dec. 31, 2010. The plans are funded by the Corporation in accordance with governing regulations and actuarial valuations. In addition, in Canada, we provide some optional plans for employees to enhance their financial wellness and retirement savings, with group RRSP and TFSA plans.

In Australia, employees can nominate a superannuation fund for superannuation contributions. The Australian superannuation scheme is compulsory for employers with contributions required at a rate set by the government.

Other Employee Benefit Programs
TransAlta provides competitive benefit programs for most of our employees (options are dependent on the countries in which we operate). We also provide benefit programs based on negotiated union agreements in some locations.

Our flexible benefits plans provide employees and their families with choices of coverage including, among others, extended health, dental, vision, life insurance, critical illness, accident, disability and a health spending account.

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 Mar. 1, 2017.

Talent and Employee Development
Talent and employee development is viewed as a key pillar of organizational health. Investing in our employee development enhances employees' skills and improves productivity and engagement. This contributes to a strong corporate culture that provides value for TransAlta.

In 2019, we launched our Leadership Development Program. This program provides 143 leaders or future leaders with fundamental leadership skills and tools. Training programs focused on a variety of leadership competencies for leaders with various years of management experience. All leaders in Canada also completed mandatory Violence in the Workplace training.

In addition, in 2019 we developed and launched our Operations Manager Development Program. This is an internally designed program to develop future plant managers and operations leaders by providing on-the-job experience and structured learning activities within multiple business units across the organization. Participants learn through an 18-month program of rotational assignments in various operational facilities (Coal, Gas, Wind and Hydro) as well as through Corporate business units (Asset Management, Commercial, Energy Trading & Marketing, Finance, Human Resources, Indigenous & Stakeholder Relations, Growth and Supply Chain). In 2019, we had seven participants in this program.

We also continued to offer our existing internal programs to employees across the organization. This includes our Elevate Program, a six-month peer-led leadership training program. This program first launched in 2017, and in 2019, we had 100 participants. Since the launch of this program, 215 leaders and future leaders have participated.

Another internal program that we continue to offer is Execution Engine. This program was designed to build capacity for our people to create an organization that is both efficient and adaptive. The training program was built on research regarding what is needed for our people to help drive and sustain change. To date, approximately 850 employees have taken this course. In December 2019, we also launched an internal leadership library that is updated monthly and gives all employees access to articles about leadership development.

Social and Relationship Capital

We strive to create shared value for our stakeholders through 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 positive relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners in the areas where we operate.

Indigenous Relationships and Partnerships
At TransAlta, we value our relationships and partnerships with stakeholders and our Indigenous neighbours. Our Indigenous Relations team focuses on community engagement, employment, economic development and community investment. We ensure that TransAlta's principles for engagement are upheld and that the Corporation fulfills its commitments to Indigenous communities. Efforts are focused on building and maintaining solid relationships and establishing strong communication channels that enable TransAlta to share information regarding operations and growth initiatives, gather feedback to inform project planning and understand priorities and interests from communities to better address concerns.

Methods of engagement include:

- Relationship building through regular communication and in-person meetings with representatives at various levels within Indigenous community organizations;
- Hosting company-community activities that share both business information and cultural lessons;
- Maintaining consistent communications with each community and following appropriate community protocols and procedures;
- Participating in community events such as powwows and blessing ceremonies; and
- Providing both monetary and in-kind sponsorships for community initiatives.

TransAlta is proactive with initiating engagement early on in project development to allow concerns to be identified promptly and addressed, minimizing potential project delays. We conduct consultation primarily during project development and decommissioning and maintain engaged communication throughout the operation phase. We work with communities to build a relationship with a foundation of ongoing communication and mutual respect.

In 2019, TransAlta partnered with Indspire, Canada's national Indigenous registered charity, and we were able to award 14 bursaries of $3,000 each. The Indigenous recipients were from the following communities: Aamjiwnaang First Nation, Blood Tribe, Ermineskin Cree Nation, Paul First Nation, Piikani Nation, Samson Cree Nation, Simpcw First Nation, Squamish Nation, Sunchild First Nation and Tsuut'ina Nation.

We currently hold a silver-level standing with the Canadian Council for Aboriginal Business's Progressive Aboriginal Relations ("PAR"). Certification occurs every three years and is a comprehensive, third-party audit conducted by PAR verifiers. To support this initiative, TransAlta introduced an internal practice and knowledge centre that provides employees with resources and information to support the advancement of Indigenous relations at TransAlta.

In 2020, TransAlta continues to support Indigenous access to education through our Indigenous funding program with the Southern Alberta Institute of Technology (SAIT). TransAlta recognized a gap in federal and provincial funding for academic upgrading, which could contribute to a barrier for many Indigenous students. This program provides the critical financial support to aspiring Indigenous students applying to SAIT who require high school upgrading in order to qualify for a trade program.

In 2019, we also supported an Indigenous Leadership Program at the Banff Centre for Arts and Creativity. Approximately 300 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 45 bursaries for members of Indigenous communities to attend programs and share what they have learned with their comminuties. Participants have come from communities across Alberta and British Columbia including Alexis Nakota Sioux Nation, Bearspaw First Nation, Chiniki First Nation, Enoch Cree Nation, Ermineskin Cree Nation, Fort McKay First Nation, Blood Tribe, Montana First Nation, Paul First Nation, Piikani Nation, Samson Cree Nation, Siksika Nation, Squamish Nation, Tsuut'ina Nation and Wesley First Nation.

Public Health and Safety

We seek to preserve public health and safety. It is our goal to maintain security for our employees and the peoples and communities where we operate.

We specifically look to minimize the following risks:

- Harm to people;
- Damage to property;
- Operational liability; and
- Loss of organizational reputation and integrity.

We work to prevent incidents and lower our risk by administering controls such as restricting physical access around and into our operating sites. The TransAlta Corporate Emergency Management program is in place to prepare employees for an emergency incident. Through this program, emergency preparedness training is implemented across our fleet in an all-hazards approach to public safety and emergency response. Each site also has an Emergency Response Plan and completes on-site drills and exercises specific to the incidents that could occur at each location. Our business continuity plan also helps prevent an interruption to operations. The program has corporate oversight and is supported by the Corporate Emergency Management Team in an emergency situation. The program has executive sponsorship and is focused on the protection of our people, assets, information and reputation.

Data and Digital Asset Protection
Our digital assets are also something we work hard to protect. Cybersecurity risks can include compromise of data integrity, hacking, social engineering, compromise of operations and infrastructure, credential breaches, attacks through third-party vendors and service providers, attacks involving artificial intelligence and machine learning, and cybersecurity staff turnover. Given the ever-evolving nature of cyber attacks, we are consistently adapting to address threats with a comprehensive cybersecurity program that consists of three pillars: technology, processes and resourcing. Each of these pillars can be reinforced independently to address specific cyber risks and threats. Through this program, TransAlta continually implements proactive controls and safeguards to mitigate the cybersecurity risks and threats posed to the organization.

Refer to the Governance and Risk Management - Cybersecurity Risk section of this MD&A for further details.

Stakeholder Relationships
Fostering relationships with our stakeholders is important to TransAlta. Driven by our values, we seek to maximize value creation for our stakeholders and TransAlta. We take a proactive approach to building relationships and understanding the impacts our business may have on local stakeholders.

TransAlta Stakeholders
To act in the best interests of the Corporation and to optimize the balance between financial, environmental and social value for both our stakeholders and TransAlta, we seek to:

- Engage regularly with stakeholders about our operations, growth prospects and future developments;
- Consider feedback and make changes to project designs and plans to resolve and/or accommodate concerns expressed by our stakeholders; and
- Respond in a timely and professional manner to stakeholder inquiries and concerns and work diligently to resolve issues or complaints.

Our stakeholders are identified through stakeholder mapping exercises conducted for each facility and prospective project development or acquisition. Through decades of stakeholder relations in the areas of our facilities, we have developed a strong understanding of who our stakeholders are and have gained understanding of our stakeholders' issues and concerns.

Our principal stakeholder groups are listed in the following table.

TransAlta Stakeholders		
Non-governmental organizations (NGOs)	Community Associations and Organizations	Connecting Transmission Facility Operators
Regulators	Industry Organizations	Communities
Charitable Organizations/Non-profit	Standards Organizations	Retirees
All Levels of Government	Media	Residents/Landowners
Suppliers	Business Partners	Investor Organizations
Contractors	Unions/Labour Organizations	Financial Institutions
Government Agencies	Forest Associations/Industry	Mineral Rights Owners
System Operators	Oil & Gas Associations/Industry	Railroad Owners
Customers	Think Tanks	Utility Owners
Municipalities	Academics	PPA Buyers

Engagement Framework
Our stakeholder engagement framework is modelled after 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. Although we no longer certify under ISO 14001, we continue to operate within its established best practices.

Methods of Engagement
In order to run our business successfully, we maintain open communication channels with stakeholders. We commit to timely and professional resolution using values-based dialogue. We work internally and with each stakeholder to identify how to mitigate further issues.

Examples of our methods of engagement are listed in the following table.

Information & Communication	Dialogue & Consultation	Relationship Building
Open houses, town halls and public information sessions	In-person meetings with local groups and communities	Community Advisory Bodies
Newsletters, telephone conversations, emails and letters	Meetings with individual stakeholders e.g. landowners and residents	Capacity Agreements
Websites	Targeted audience sessions	Sponsorships and donations
Social media postings	Tours of our facilities and sites	Hosting events

A key focus of our work is to support the business growth through proactive engagement with stakeholders in all of our geographic operating areas in Australia, Canada and the US in order to develop and maintain relationships, assess needs and fit and to seek out collaborative and sustainable value creation opportunities. This helps ensure any stakeholder concerns are identified and can be addressed early in the development process, minimizing project delays. We conduct consultation primarily during project development and decommissioning and maintain engaged communication throughout operations. As an example, we implemented our stakeholder engagement program with stakeholders and Indigenous groups in connection with the proposed repowering at the Sundance and Keephills facilities. We filed our regulatory applications in December 2019, and our stakeholder engagement program will continue for the entire life cycle of the facilities.

Engagement Tracking and Reporting
Our Stakeholder and Indigenous Relations tracking program functions as an enterprise-wide communication recordkeeping tool, which is managed by our Stakeholder and Indigenous Relations team. This capacity fulfills our requirements for consultation with stakeholders and Indigenous groups alike, and is capable of producing regulatory reports as proof of engagement and consultation efforts. The tool can store email conversations, documents and voicemail messages related to any project, event or issue, and display them in a report format. It can also produce an array of statistical reports showing frequency and volume of engagement based on project, stakeholder, stakeholder group or keywords. This tracking program decreases the time and cost required to submit proof of engagement to government agencies.

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, Finance and Risk Committee by writing to the AFRC or by making submissions via the Corporation's toll-free telephone or online Ethic Helpline (see the Governance and Risk Management - Whistleblower System section in this MD&A 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 submit questions or inquiries to the Board, to which the Corporation will respond. A copy of the Shareholder Engagement Policy is available on our website at www.transalta.com. 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.

Throughout 2019, representatives of the Board engaged extensively with the Corporation's significant shareholders. Specifically, since Jan. 1, 2019, the Board has met with 15 shareholders representing 42 per cent of the Corporation's total issued and outstanding common shares. In addition, in Sep. 2019, TransAlta held an Investor Day at which we provided detailed information about the Corporation's strategies, plans, operations and past, present and expected performance. The Investor Day afforded shareholders the opportunity to engage with the Corporation's senior management.

Customers

As one of the largest Alberta electricity generators providing energy services, our team serves businesses with:

- Energy consumption and cost management solutions;
- Market price risk and volume exposure mitigation;
- Sustainability initiatives such as self-generated electricity and environmental attributes (such as carbon offsets); and
- Monitoring of energy market design changes, price signals and applicable and available incentives.

The Customer Solution team at TransAlta has maintained a large portfolio of customers in Alberta across a broad range of industry segments including: commercial real estate, municipal, manufacturing, industrial, hospitality, finance and oil and gas. TransAlta is proud of the service we provide to our customers, which is evidenced by the achievement of over 90 per cent customer retention for the last three years.

We are focused on helping our customers in ways uniquely suited to achieve their sustainability goals. One example is through TransAlta's fleet of on-site cogeneration facilities. Cogeneration is the process of generating electricity and steam simultaneously. When constructed on-site, the construction of additional transmission lines is not required, which avoids disruption to the environment. It also reduces the natural gas required for some industrial processes by using high efficiency steam production rather than boilers. Examples of industrial processes that utilize cogeneration include gas processing, steam-assisted gravity drainage oil sands extraction, chemical manufacturing, and pulp and paper production. Cogeneration is recognized by regulatory bodies for its efficiency in generating power versus traditional methods, and thus can potentially produce Emission Performance Credits that can be used to satisfy our customers' regulatory obligations or sold as additional revenue.

We provide on-site generation for large mining and industrial customers. This requires us to be continually engaged with these customers to ensure that current electricity requirements are provided safely, reliably and cost effectively, but also that their future electricity requirements be satisfied alongside the benefits of lower GHG emissions.

Another way we can contribute to our customers' sustainability goals is through the use of environmental attributes. Environmental attributes that we have the ability to generate, trade, purchase and sell, include: EPCs, Alberta carbon offsets, Renewable Energy Credits ("RECs") and emission offsets. Alberta carbon offsets can be voluntarily generated by Alberta projects, which meet Alberta carbon offset system qualification protocols. Our Alberta wind facilities generate Alberta carbon offset credits. RECs are produced from our renewable energy assets (wind, hydro and solar) and can be traded in voluntary carbon markets or sold to customers. RECs can be used to meet regulatory requirements when a target for renewable energy generation is set by a jurisdiction or can be used to voluntarily 'green' electricity procurement. Emissions offsets are produced from voluntary projects that reduce emissions in sectors of the economy not covered by carbon reduction regulations. The optimization of environmental attributes can be used as a cost-effective way, for the Corporation or our customers, to lower compliance costs attributed to carbon policies or renewable portfolio standards, or utilized to achieve voluntary corporate sustainability or carbon reduction goals.

To learn more, please visit our website at www.transalta.com/customers.

Supply Chain

We continue to seek solutions to advance supply chain sustainability. In 2017, we optimized our global supply chain management operations by implementing a platform that supports increasing supply chain efficiency, reducing lead times, lowering costs and improving supplier performance. As we explore major projects, we assess vendors both at the evaluation stage and as part of information requests on such elements as safe work practices, environmental practices and Indigenous spend. This means, for example, getting information on:

- Estimated value of services that will be procured though local Indigenous businesses;
- Estimated number of local Indigenous persons that will be employed;
- Understanding overall community spend and engagement; and
- Understanding the state of community relations through interview processes and stakeholder work.

In early 2019, the Board of Directors adopted a Supplier Code of Conduct that applies to all vendors and suppliers of TransAlta. Under this 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 via TransAlta's Ethics Helpline.

Community Investments

In 2019, TransAlta contributed approximately $2.1 million in donations and sponsorships (2018 - $2.4 million). One of our significant community investments each year is to United Way campaigns across Canada and the US. This year, TransAlta employees, retirees, contractors and the Corporation raised over $1.2 million for the United Way.

In 2019, we continued to focus our community investment on priority areas for TransAlta, including environment, education and leadership, health and human services, and arts and culture. Some of our partnerships included:

- Indspire – Through our new partnership with Indspire in 2019, TransAlta was able to almost double the number of bursaries available for Indigenous students through Indspire's matching program. There were 14 bursaries awarded in 2019. Formerly the National Aboriginal Achievement Foundation, Indspire is Canada's national charity for Indigenous education;

- Mother Earth's Children's Charter School - Located in treaty six territory, near Stony Plain, Alberta and our Alberta coal operations, Mother Earth Children's Charter School ("MECCS") has become an important part of TransAlta's community investment program. MECCS offers Kindergarten to Grade 9 and is cited as Canada's first and only Indigenous children's charter school. The school was established in 2003 to help provide Indigenous students with an education based strongly on cultural context rather than a traditional western educational model. Approximately 95 per cent of MECCS students are of Indigenous ancestry, with students coming from Paul First Nation, Enoch Cree Nation, Alexis Nakota Sioux Nation, Alexander First Nation, Alberta Beach, Stony Plain and Edmonton. The student population is diverse and includes Métis, Cree, Nakota Sioux and Stoney. Beginning in 2014, TransAlta has made an annual $35,000 donation to the school. In addition, each year at Christmas, TransAlta staff purchase Christmas presents for the students. Volunteers from TransAlta travel to the school to deliver the gifts providing both our employees and the students the opportunity to engage with each other;

- The Calgary Stampede – Founded in 2017, the TransAlta Performing Arts Studio at Stampede Park continues to provide a year-round facility for Calgary Stampede Foundation and Calgary's youth performing arts groups to rehearse, train and celebrate the arts;

- Southern Alberta Institute of Technology ("SAIT") – Working with SAIT, TransAlta continued to support Indigenous access to education through our Indigenous funding program that addresses a gap in federal and provincial funding for Indigenous academic upgrading;

- TransAlta Tri-Leisure Centre - TransAlta continues to be a proud sponsor of this facility. The TransAlta Tri-Leisure Centre is a sporting and recreation destination for many active and involved residents from the communities of Parkland County, Spruce Grove and Stony Plain in Alberta. At the facility, thousands of local residents, and many of our employees, participate in a wide range of sporting and cultural activities and join together in many community causes;

- Banff Centre – TransAlta continued its financial support for the Indigenous Leadership Program at the Banff Centre for Arts and Creativity. Over the past five years, TransAlta's support has provided 45 bursaries for members of Indigenous communities to attend programs across Alberta and British Columbia; and

- Energy Transition Support - On July 30, 2015, in Washington State, we announced a US$55 million community investment over 10 years to support energy efficiency, economic and community development, and education and retraining initiatives. 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. Specific projects that the boards funded in 2019 include rebuilding a playground (which included the installation of energy-efficient lighting and accessible surfaces and walkways), the construction of a training facility at Centralia College and funding Washington State's first electric school bus.

Natural Capital

We continue to increase financial value from natural or environmental capital-related business activities, while reducing our environmental footprint and potential risk factors related to environmental impacts. Comparable EBITDA from renewable energy generation in 2019 was $341 million (2018 - $342 million). Our revenue in 2019 from environmental attribute sales was $27.6 million (2018 - $21.6 million). In addition, in 2019 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 trends in our natural capital:

Year ended Dec. 31	**2019**	2018	2017
Renewable energy comparable EBITDA	**341.0**	342.0	289.0
Environmental attribute sales revenue	**27.6**	21.6	27.7
GHG emissions (million tonnes CO_2e)	**20.6**	20.8	29.9

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 electricity transition. Natural gas plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. TransAlta operates simple and combined-cycle natural gas units and cogeneration facilities. We are planning to convert our Alberta coal units to natural gas in the 2020 to 2025 time frame, and by the end of 2025, our generation mix will be only from natural gas and renewable energy.

Regardless of the fuel type, we place significant importance on environmental compliance and continued environmental impact mitigation, while seeking to deliver low-cost and reliable electricity. The Corporation endeavours to be environmentally responsible and recognizes that the competitive pressures for economic growth and cost efficiency must be integrated with sound sustainability management, including environmental stewardship. The Corporation is subject to environmental laws and regulations that affect aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of waste and hazardous substances. The Corporation's activities have the potential to impair natural habitat, damage vegetation and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require the Corporation to obtain and comply with a variety of environmental registrations, licenses, permits and other approvals. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Corporation. 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 via our environmental management systems include environmental incidents and spills, land use, water use and waste management.

Environmental Governance

TransAlta's Governance, Safety and Sustainability Committee 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. More details on governance can be found in our Governance and Risk Management section of this MD&A.

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 over 20 years, and our systems and knowledge of management systems are therefore mature. Only two facilities do not have ISO 14001 aligned EMS in place, although these facilities do have a comparable EMS in place. This is due to commercial arrangements (TransAlta is not the operator of those two sites). Aligning with ISO 14001 provides assurance that our systems are designed to continuously improve performance.

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 management 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 and Battery Storage
Since 2005, we have added approximately 1,300 MW in renewable energy capacity. We continue to operate over 900 MW of hydro energy and our experience with hydro operations spans over 100 years. In 2015, we made our first solar investment in a 21 MW solar facility in Massachusetts, and we continue to look for opportunities to develop and operate solar energy. Our production from renewable energy in 2019 offset the equivalent of approximately 1.6 million tonnes of carbon dioxide equivalent, or the removal of approximately 340,000 cars from the roads in 2019.

In 2020, we will commission the first utility-scale battery storage project in Alberta, located at our Summerview Wind Farm. The project will use Tesla battery technology and will have a capacity of 10 MW.

Natural Gas
Natural gas plays an important role in the electricity sector, providing low-emission baseload and peaking generation to support system demands and intermittent renewable generation. TransAlta operates simple cycle, combined-cycle, and cogeneration facilities in Canada and Australia. Natural gas facilities provide highly efficient electricity and, in the case of cogeneration, steam production, directly to customers and for the wholesale markets. TransAlta is a significant operator of natural gas electricity in Canada and Australia.

Coal Transition
Our coal-to-gas conversion plan in Alberta is expected to significantly reduce our environmental footprint. As a result of our coal-to-gas conversions, energy use, GHG emissions, air emissions, waste generation and water usage are expected to significantly decline. Conversion of coal-fired power generation to gas-fired generation will eliminate all mercury emissions, the majority of particulate and sulphur dioxide emissions ("SO_2") as well as significantly reducing our nitrogen dioxide emissions ("NO_x"). Converting GHG-intensive coal facilities to natural gas will support significant reductions in GHGs (approximately 40 per cent reduction), while supporting reliability, affordability and growth of renewable electricity in Alberta. Converted coal facilities will use lower carbon natural gas (new methane reduction regulations on flaring and venting will reduce GHG emissions for natural gas producers) while supporting our local gas producers through the use of up to 700,000 GJs of natural gas per day.

Environmental Incidents and Spills
Protecting the environment and minimizing our impact to the environment supports healthy ecosystems and mitigates our environmental compliance risk and reputational risk. We maintain procedures for environmental incidents similar to our safety practices, with tracking, analyzing and active management to minimize occurrences. With respect to biodiversity management (management of ecosystems, natural habitats and life in the areas we operate), 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 incidents are separated into two categories: significant environmental incidents and regulatory non-compliance environmental incidents. We define regulatory non-compliance environmental incidents as events that involved a non-compliance event but did not have an impact on the environment. For example, a technical issue with a computer system for gathering real-time data could cause us to be out of compliance with local regulation or our EMS, but there is no direct consequence for the physical environment. All other events are captured as significant environmental incidents and these are where we deem there to be a material impact to the environment. In 2019, we recorded three significant environmental incidents (2018 - one incident). We recorded six non-compliance environmental incidents in 2019 (2018 - six incidents).

Our three significant environmental incidents in 2019 occurred at two of our wind facilities in the US. At our Lakeswind wind facility in Minnesota, we discovered a bald eagle mortality. At our Wyoming wind facility, we discovered two golden eagle mortalities. Root cause analysis investigations were performed on each eagle mortality and we found no causal factors or root causes related to human behaviour or equipment failure being involved in the incidents. These incidents were unusual and we have not had an eagle mortality across our wind fleet since 2015. For all incidents we collaborated with authorities and there were no enforcement actions in respect of such mortalities. Despite inconclusive findings, in order to reduce the risks of future impacts to protected eagle species, we are working on indirect corrective actions that include reviewing the potential for an updated bird monitoring study to be conducted at Lakeswind and Wyoming wind or other at-risk sites.

The following are the significant environmental incidents by fuel types:

Year ended Dec. 31	2019	2018	2017
Coal	—	1	1
Gas and renewables	3	—	1
Total significant environmental incidents	**3**	1	2

The following outlines regulatory non-compliance environmental incidents by fuel types:

Year ended Dec. 31	2019	2018	2017
Coal	3	4	3
Gas and renewables	3	2	—
Total regulatory non-compliance environmental incidents	**6**	6	3

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 that could occur at our operation sites are hydrocarbon spills. Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare that we experience large spills, which would adversely impact the environment and the Corporation. Spills that do occur are always addressed with a critical time factor. The estimated volume of spills in 2019 was 530 m^3 (2018 - 5 m^3). Spill volumes in 2019 were higher due to a 527 m^3 spill at our Sarnia cogeneration facility. This was not a traditional product spill and was a wastewater effluent limit exceedance from a sump. There was no enforcement action associated with this spill.

Air Emissions

Our coal facilities emit a number of air emissions that we track, analyze and report to regulatory bodies. We also work on mitigation solutions depending on the type of air emission. We report our major air emissions from coal, which includes NO_x, SO_2, particulate matter and mercury. We will continue to reduce air emissions in our existing fleet through our conversion and retirement of coal units in Alberta and Washington State. We are well underway and remain on track to achieve our target of 95 per cent SO_2 emission reductions over 2005 levels by 2030. Since 2005, we have reduced SO_2 emissions by 77 per cent. As noted above, we are on track to achieve our SO_2 target by 2025, well ahead of our 2030 goal. This allows flexibility as we convert coal facilities to natural gas and expand our natural gas fleet. We continue to model and evaluate this target to ensure a balance of growth and appropriate air emission reductions. We continue to capture 80 per cent of mercury emissions at our coal plants and by 2025, mercury emissions will be eliminated following the coal-to-gas conversions. Particulate matter and SO_2 emissions will also be virtually eliminated or considered negligible.

None of our Alberta coal facilities are located within 50 kilometres of dense or urban populations, but our Centralia coal facility in Washington State is 40 kilometres from a dense or urban population. As per guidance from SASB, "a facility is considered to be located near an area of dense population if it is located within 49 kilometres of an area of dense population" (being deemed to be a "minimum population of 50,000 persons"). The Centralia facility has two units and we are retiring one unit at the end of 2020 and the additional unit at the end of 2025, at which time air emissions from our coal facilities will be eliminated.

Our gas facilities emit low levels of NO_x that triggers reporting obligations to national regulatory bodies. These gas facilities also produce trace amounts of SO_2 and particulate matter, but at levels that are deemed negligible and do not trigger any reporting requirements or compliance issues. Many of our gas facilities are located in very remote and unpopulated regions, away from dense urban areas. Our Sarnia, Windsor, Ottawa and Fort Saskatchewan gas facilities are our only facilities with air emissions within 49 kilometres of dense or urban environments.

Our total air emissions in 2019 decreased compared with 2018 levels. Specifically, NO_x was reduced eight per cent, mercury was reduced three per cent, particulate matter was reduced one per cent and SO_2 was reduced 18 per cent over 2018 levels. Reduction in most emissions were largely due to an increase in co-firing (gas and coal) at our Alberta thermal facilities. Particulate matter emissions were adjusted historically to reflect our estimation on the level of PMs from road dust at our Alberta mining operations. We continue to mature our ability to estimate this data in line with guidance from Government of Canada.

Year ended Dec. 31	**2019**	2018	2017
Sulphur dioxide (tonnes)	**15,900**	19,300	36,200
Nitrogen dioxide (tonnes)	**25,800**	28,000	44,400
Particulate matter (tonnes)	**8,200**	8,400	11,400
Mercury (kilograms)	**60**	70	110

Water

Our principal water use is for cooling and steam generation in our coal and gas plants, but our hydro operations also require water flow for operations. Water for coal and gas operations is withdrawn primarily from rivers where we hold permits to withdraw water and must adhere to regulations on the quality of water that is discharged. The difference between withdrawal and discharge, representing consumption, is due to several factors, which includes evaporation loss and steam production for customers. Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2019 we withdrew 286 million m^3 (2018 – 245 million m^3) and returned approximately 218 million m^3 (2018 – 208 million m^3) back to its source or 76 per cent. Overall water consumption was 68 million m^3 (2018 – 37 million m^3). Water withdrawal and consumption was much higher in 2019 due to increased production at our Centralia coal facility. Production was up 1,787 GWh in 2019 compared to 2018, due mainly to higher merchant pricing in the first half of 2019 and timing of dispatch optimization.

Our historical 2017 water from environment volume was revised in 2019 as a result of an adjustment to water volumes from our South Hedland facility. South Hedland began commercial operations in 2017 and water data was reported in an incorrect unit. This adjustment resulted in our 2017 water from environment changing from 213 m^3 to 211 m^3. Subsequently, water consumption (water from environment minus water to environment) also changed as a result and was revised from 41 m^3 to 39 m^3.

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

Year ended Dec. 31	**2019**	2018	2017
Water withdrawal	**286**	245	211
Water discharge	**218**	208	172
Total water consumption	**68**	37	39

Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customer). The facility operates as a once-through non-contact cooling system for our steam turbines. This means large amounts of water flow in and out of the system, as opposed to more advanced technology, which recycles water in cooling towers (more of a closed system). Despite large withdrawals from the adjacent St. Clair River to support our Sarnia operations, we return approximately 93 per cent of the water withdrawn. Water from this source is currently at "low risk" as per analysis from the SASB-endorsed Aqueduct Water Risk Atlas tool.

The Aqueduct Water Risk Atlas tool also highlights that water risk is high at our interior and southern Western Australia facilities due to high interannual variability in the region. Interannual variability refers to wider variations in regional water supply from year to year. Our water supply at these facilities is provided at no cost under PPAs with our mining customers, hence our risk is significantly mitigated. In addition, conservation and re-use strategies aimed at recycling water for mining operational needs have been developed. All water used in the region is sourced from scheme water, and with gas and diesel turbine water use, water wash techniques and frequency of activities are continually modified to minimize consumption and environmental impact. At the South Hedland facility in Western Australia, water risk is also high due to the risk of flooding in the region. The South Hedland facility was built above normal flood levels to mitigate potential risk from flooding. During a recent category 4 cyclone event in the area and associated flooding in the region, the South Hedland facility stayed dry and continued to generate power for the region. In addition, the South Hedland facility has developed a Water Efficiency Management Plan with Water Corporation WA, the principal supplier of water, wastewater and drainage services in Western Australia. Initiatives are aimed at reducing water consumption and costs through innovative technology and efficiencies identified through plant management.

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 and we have adopted a target to fully reclaim this mine by 2040. Our Highvale mine in Alberta is actively mined with certain sections undergoing reclamation. Our reclamation plans at Highvale 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 2019, we reclaimed 114.9 acres (46.5 hectares) at our Highvale mine, which was above our target of 110 acres (45 hectares). We also reclaimed 160.6 acres (65 hectares) of land at our Centralia mine.

Across our mining operations, to date we have reclaimed approximately 12,000 acres (4,800 hectares), which is approximately 38 per cent of land disturbed. Since 1991, we have planted approximately 2.5 million trees as part of this reclamation work.

Waste
In 2019 our operations generated approximately 1.5 million tonnes of primarily non-hazardous waste (2018 - 1.6 million tonnes). Only 0.1 per cent of waste volumes are hazardous materials. In 2019, only 0.1 per cent of waste was directed to landfill. From the remaining 99.9 per cent, 50 per cent was returned to the mine (ash from coal combustion), 49 per cent was reused and the remaining 0.4 per cent was recycled. Historical 2018 waste volumes were revised in 2019 due to misreported volumes of ash disposal from our Keephills facility.

Our reuse waste or byproduct waste is generally sold to third parties. 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 generate electricity from the sun. In addition to combustion of fuel sources, we also track combustion of gasoline or diesel in our vehicles and the electricity use and fuel use for heating (such as natural gas) in the buildings we occupy. Knowledge of how much energy we use allows us to optimize and create energy efficiencies. As an electricity generator, we continually and consistently look for ways to optimize or create efficiencies related to the use of energy. As an example, in 2019 we supported a study conducted by Stanford University to understand how to improve wind production. The research showed that angling turbines slightly away from the wind can boost energy produced and even out variable supply. Our coal-to-gas converted plants are also expected to see a reduction in total energy use, as the utilization of these plants is expected to be lower than historical utilization levels.

The following captures our energy use (millions of gigajoules). Energy use declined by four per cent over 2018 primarily as a result of reduced power production (lower plant utilization) at Alberta thermal.

Year ended Dec. 31	**2019**	2018	2017
Coal	**296.0**	309.8	447.4
Gas and renewables	**49.1**	48.6	49.4
Corporate	**0.1**	0.1	0.1
Total energy use	**345.2**	358.5	496.9

Weather
Abnormal weather events can impact our operations and give rise to risks. Due to the nature of our business, our earnings are sensitive to weather variations from period to period. Variations in winter weather affect the demand for electrical heating requirements. Variations in summer weather affect the demand for electrical cooling requirements. These variations in demand translate into spot market price volatility. Variations in precipitation also affect water supplies, which in turn affect our hydroelectric assets. Also, variations in sunlight conditions can have an effect on energy production levels from our solar farm. Variations in weather may be impacted by climate change resulting in sustained higher temperatures and rising sea levels, which could have an impact on our generating assets. Ice can accumulate on wind turbine blades in the winter months. The accumulation of ice on wind turbine blades depends on a number of factors, including temperature and ambient humidity. The accumulation of ice on wind turbine blades can have a significant impact on energy yields, and could result in the wind turbine experiencing more downtime. Extreme cold temperatures can also impact the ability of wind turbines to operate effectively and this could result in more downtime and reduced production. In addition, climate change could result in increased variability to our water and wind resources.

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

During the past five years, deviations from expected weather patterns had the following impacts on our annual financial results:

- 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 Highvale mine in Alberta was subjected 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 material impacts relating to climate change. Our climate change reporting is structured as per guidance from the Financial Stability Board's Task Force on Climate-Related Financial Disclosure 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 at www.transalta.com/sustainability/climate-change-management.

Key Messages
- The GSSC includes in its mandate that it will review guidelines and practices relating to environmental protection and the Corporation's plans with respect to environmental impact;
- Our strategy involves moving away from GHG-intensive coal and achieving 100 per cent clean energy by 2025, represented by renewables and gas;
- Our business is showing resilience to two degrees of global warming by reducing GHG emissions – we have a target to reduce 19.7 million tonnes of CO_2e by 2030 over 2015 levels. To date we have achieved 59 per cent of this target;
- We are well positioned to build renewable energy facilities and lower-carbon gas facilities to support customer sustainability goals to decarbonize; and
- We have reduced 21 million tonnes of CO_2e since 2005, which is a 50 per cent reduction over the time period.

Governance
The highest level of oversight on climate-change-related business impacts is at our Board level, specifically by the GSSC and the AFRC. Macro issues and opportunities such as coal GHG emissions and the phase-out of coal power generation, cost-competitiveness of renewable energy and customer preferences toward lower carbon energy have been at the forefront of strategic discussions with our executive and Board and reflected in our actions to move away from coal, establish a 2030 GHG reduction target and grow our generation capacity from renewable energy and gas.

Our GSSC has oversight of climate-related issues as noted in the GSSC Charter. The GSSC meets on a quarterly basis. One of the mandates of the GSSC Charter is to monitor and assess climate change risks and compliance with associated legislation and public reporting. The GSSC also reviews guidelines and practices relating to environmental protection, including the mitigation of pollution and climate change and considers whether the Corporation's policies and practices relating to the environment are being effectively implemented and advises regarding the development of policies and practices regarding climate change, greenhouse gas and other pollutants".

Strategy
TransAlta, and the electricity sector in general, is at the forefront of reducing GHG emissions, utilizing innovation with lower-carbon and zero-carbon solutions (e.g., renewable energy, natural gas, distributed power generation, battery storage etc.) and are showing a path to resiliency in a low-carbon world. In addition to climate resiliency, front of mind for TransAlta and our sector is reliability of electricity supply and affordability for customers. To support our own path to reduce our GHG footprint and ensure climate resiliency, we have a corporate goal to reduce our GHG emissions by 60 per cent by 2030 over 2015 levels, while growing renewable energy and natural gas. We believe natural gas plays a strong role in supporting grid reliability and supporting customer goals of affordability. Scenario modelling of our GHG target shows that meeting our GHG target aligns us, under many scenarios, with science-based target setting. 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 Targets Initiative.

Our business units and operations consistently seek energy-efficiency improvements, opportunities to integrate clean combustion technologies and development of emissions offset portfolios to achieve emissions reductions at competitive costs. 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 and reduce our GHG impact.

Our investments and growth in renewable electricity are highlighted by our diverse portfolio of renewable energy-generating assets. We currently operate close to 2,400 MW of hydro, wind and solar power. In 2019, we completed construction and commercial operation of an additional 119 MW of wind generation in the US. Today our diversified renewable fleet makes us one of the largest renewable producers in North America, one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta. Production from renewable electricity in 2019 resulted in avoidance of approximately 1.6 million tonnes of CO_2e, which is equivalent to removing over 620,000 vehicles from North American roads over the same year.

As previously noted, we seek to commoditize carbon through trading and the generation and sale of environmental attributes. Annual revenue generation from the sale of environmental attributes (Alberta carbon offsets and RECs) in 2019 was $28 million.

Risk Management
Climate change risks are monitored through our company-wide risk management processes and are actively managed. Climate change risks and opportunities are identified at the Board level, executive and management level, business unit level (coal, gas, wind, solar and hydro) and through our corporate function (e.g. government relations, regulatory, emissions trading, sustainability, commercial, customer relations and investor relations). The business unit and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board.

Climate change risks at the asset or business unit level are identified through our Environmental Management Systems, asset management function and systems, our energy and trading business, active monitoring, active participation/communication with stakeholders, liaison with our corporate function, active participation in working groups and more.

Our climate change risks are divided into two major categories: (1) risks related to the transition to a lower-carbon economy, and (2) risks related to the physical impacts of climate change.

1. Transition Risks

We seek to understand the impact on our business as the world shifts to a lower carbon society. We participate in ongoing decisions related to climate policy and regulation.

Policy and Legal Risks

Ongoing and Recently Passed Environmental Legislation
Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business. For further details, see below and the Governance and Risk Management section of this MD&A.

Canadian Federal Government
Federal Carbon Pricing on GHG
On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the Canadian federal government implemented a national price on GHG emissions. The price began at $20 per tonne of CO_2e emissions in 2019, and will rise by $10 per year until reaching $50 per tonne in 2022. In 2022, there will be a review of the Output-Based Pricing Standard and other aspects of the GGPPA.

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

The OBPS regulates large emitters' carbon intensity by setting a sectoral performance standard (benchmark) of GHG emissions per unit of production (e.g. tonnes CO_2e/MWh) for electricity generators. Emitters exceeding the benchmark generate carbon obligations and those emitters that perform below the benchmark generate emission performance credits. Emitters can meet their obligations by reducing their emission intensity, buying carbon credits from others (offsets or emission performance credits) or making compliance payment to the government.

Other jurisdictions were compliant with the GGPPA so did not have the backstop mechanism imposed in 2019. These jurisdictions must file and have their carbon pricing programs approved annually. Over future annual compliance periods, if parts or all of a province's GHG regulations fall out of compliance with the GGPPA, the federal government will impose its backstop mechanisms.

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 regulations, new and significantly modified natural gas fired electricity facilities with a capacity greater than 150 MW must meet a standard of 420 tonnes CO_2e per gigawatt hour ("tonnes CO_2e/GWh") to operate. For units with a capacity between 25 MW and 150 MW, their standard was set at 550 tonnes CO_2e/GWh. Facilities with a capacity less than 25 MW have no standard.

Under the regulations, coal-to-gas conversions will also eventually have to meet a standard of 420 tonnes CO_2e/GWh. If the first year performance test after conversion meets certain emission standards it will not have to meet the 420 tonnes CO_2e/GWh standard for several additional years past the end of its useful life.

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 tonnes CO_2e/GWh by the earlier of end-of-life under the 2012 regulations or Dec. 31, 2029.

Clean Fuel Standard
In 2016, the Canadian federal government announced plans to consult on the development of a Clean Fuel Standard ("CFS") to reduce Canada's GHG through the increased use of lower carbon fuels, energy sources and technologies. The objective of the regulation is to achieve 30 million metric tonnes of annual reductions in GHG emissions by 2030. The CFS will establish life-cycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. Under the proposed policy, coal combusted at facilities that are covered by coal-fired electricity regulations will be exempt from the regulation. Natural gas used for electricity production is currently expected to be included under the gaseous stream.

Consultation on the gaseous stream began in 2019 and will continue into 2020. Publication of the draft regulations for the gaseous stream will occur in late 2020 with final regulations expected in 2021. The gaseous stream regulation is currently expected to come into force by 2023. TransAlta continues to be engaged in the consultation process.

Alberta

Large Emitter Greenhouse Gas Regulations

On Jan. 1, 2018, the Alberta government transitioned from the *Specified Gas Emitters Regulation* ("SGER") to the *Carbon Competitiveness Incentive Regulation*. Under the CCIR, the regulatory compliance moved from a facility-specific compliance standard to a product or sectoral performance compliance standard. In 2019, the CCIR price was $30/ tonnes CO_2e, and the electricity sector performance standard was set at 0.370 tonnes CO_2e/MWh and set to decline annually. All renewable assets that received offset crediting under the SGER continued to receive credits under CCIR on a one-to-one basis. All other renewable assets that did not receive offset crediting under SGER were able to "opt-in" under CCIR and received carbon crediting up to the electricity sector performance standard until CCIR's termination at the end of 2019. Once wind projects' offset crediting standard under the SGER protocol ends, these projects will also be able to opt-in under CCIR system and be credited up to the performance standard.

On Apr. 16, 2019, the United Conservative Party ("UCP") won the Alberta provincial election with a majority government. The UCP committed to move from the CCIR to a new regulation called the *Technology Innovation and Emissions Reduction* ("TIER") regulation. TIER replaced CCIR on Jan. 1, 2020. For the electricity sector, there were negligible changes between CCIR and TIER with renewable facilities continuing to receive crediting. The carbon prices for TIER in 2020 will remain at $30/tonnes CO_2e but Alberta has not yet confirmed future price increases in line with federal requirements. The performance standard benchmark remained at 0.370 tonnes CO_2e/MWh. A review of TIER is not expected until 2023.

Facilities with emissions above the set benchmark will need to comply with TIER by: i) paying into the TIER Fund; ii) making reductions at their facility; iii) remitting emission performance credits from other facilities; or iv) remitting emission offset credits.

As required by the GGPPA, the Alberta government filed the TIER program details with the federal government. TIER was passed by the Alberta government on Oct. 29, 2019 and on Dec. 6, 2019 the federal government accepted the TIER regulation as compliant with the GGPPA for 2020.

Federal Pollution Pricing Fuel Charge (Fuel Charge)

The new UCP government repealed the Alberta carbon levy on May 30, 2019. The federal government will replace the repealed carbon levy with the Fuel Charge on Jan. 1, 2020. Alberta TIER-covered facilities are exempt from the Fuel Charge.

British Columbia

Beginning Apr. 1, 2018, BC increased its carbon tax rate to $35/tonnes CO_2e and committed to raise the price $5 per year until it reaches $50 per tonne in 2021.

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.

Large Emitter Greenhouse Gas Regulations

The Canadian federal GGPPA requires provinces to have greenhouse gas regulations and prices in place that align with the federal GGPPA. On Oct. 23, 2019, the federal government announced that Ontario large emitters would be subject to the federal backstop OBPS regulation. All covered industry facilities with annual emissions over 50,000 tonnes CO_2e are automatically covered with an opt-in provision for those emitters between 10,000 and 50,000 tonnes CO_2e annually. Ontario large emitters are currently subject to the federal backstop OBPS regulation.

On July 4, 2019, the Government of Ontario released the final regulations for the provincial Greenhouse Gas EPS. The EPS establishes GHG emission limits on covered facilities. Large emitters generating over 50,000 tonnes CO_2e or more per year will be covered with an opt-in provision for those emitters between 10,000 and 50,000 tonnes CO_2e annually. The carbon emissions limit for electricity is set at 420 tonnes CO_2e/GWh. The program also provides a method that accounts for the carbon efficiency of cogeneration units. The federal government has not accepted the EPS as compliant with the GGPPA so the OPBS remains in force for reporting purposes for 2019 obligations.

Facilities with emissions above the set reduction requirements can comply by: i) buying excess emission units from the regulator; ii) making reductions at their facility; or iii) using emission performance units generated by facilities emitting below their emission intensity limit. The first compliance period under the EPS will begin on Jan. 1 in the year in which Ontario is removed from the list of provinces to which the federal OBPS applies. Ontario has submitted the EPS for federal review.

Federal Pollution Pricing Fuel Charge (Fuel Charge)
The federal government replaced the repealed Ontario carbon levy with the Fuel Charge on Jan. 1, 2019. Ontario facilities covered by OBPS are exempt from the Fuel Charge.

Washington
In 2010, the Washington Governor's office and State Department of Ecology negotiated agreements with TransAlta related to the operation of Centralia's two coal-fired 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.

Massachusetts
The Solar Renewable Electricity Credit I (SREC I) program carved out from Massachusetts' Renewable Portfolio Standard (RPS) an initial quantity of 400 MW from small solar facilities of 10 MW or less. The initial SREC I program size was expanded and replaced by a lower-valued SREC II program. In 2018, the solar incentive program evolved into the current Solar Massachusetts Renewable Target Program that further reduced the incentive levels.

The initial SREC I program's volume target was achieved, and qualified projects under SREC I continue to generate SREC I credits for their first 10 years post-Commercial Operation Date. SREC I facilities then generate Class 1 RECs under the Massachusetts RPS for the remainder of their operational life.

Under Massachusetts' net metering program, qualified facilities connect with the local utility and generate net metering credits. Net metering credits offset the delivery, supply and customer charges and can be sold to customers from remote or on-site qualifying facilities. In 2016, the net metering program was updated to reduce the value of the net metering credits by reducing the offset to only energy costs. New projects are impacted once the net metering program volume reaches 1,600 MW. Existing facilities were grandfathered and continue to receive the full, original cost offset treatment for a period of 25 years from initial commercial operation.

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 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.

Technology Risks

Battery storage technology is an emerging risk to the large-scale power-generation model. Battery storage has the ability to enable greater adoption of renewables and result in a shift to a distributed power-generation model. We continue to evaluate battery storage for its financial viability, while monitoring the potential impact battery technology could have on natural gas power generation.

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 close to 2,400 MW.

Market Risks

Changing customer behaviour, reduced consumption and associated use of electricity could impact the demand for electricity; however, we believe this risk is mitigated somewhat by the global trend to increasingly electrify customer products, transport and more. Our low-carbon business model supports this type of future. Increased costs for natural gas supply from carbon pricing can impact us. Further discussion can be found in the Governance and Risk Management section of this MD&A. Use of renewable resources, such as the wind and sun, removes associated risk related to cost of supply.

Our Corporate function applies 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 through generation of environmental attributes (such as carbon offsets and RECs) and through our emission trading function, which seeks to commoditize and profit from carbon trading.

Reputation Risks

Consumer trends appear to be moving in favour of renewable and cleaner electricity, which may make hydrocarbon options decreasingly popular. We are invested in natural gas as it provides vital support to the electricity system and is a lower-carbon fossil fuel. We already invest significantly in renewable energy and natural gas.

2. Physical Risks

As we learn more about the physical risks associated with climate change, and weather risk in general, we seek to understand further both acute and chronic risk, which could materially impact value creation from our operations.

Acute Risks

The TransAlta South Hedland facility in Western Australia was built with climate adaptation in mind. 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. In 2019, a category 4 cyclone hit this facility. Operations were not impacted and we were able to continue generating electricity through the storm, despite wide-spread flooding and shutdown of the nearby port and associated business activities.

Chronic Risks

We have not identified any chronic physical risks that could impact our operations. However, we continue to further our understanding and integration of climate modelling into our long-term planning.

Greenhouse Gas Emissions: Metrics and Targets

In 2019, we estimate that 20.6 million tonnes of GHGs with an intensity of 0.75 tonnes per MWh (2018 - 20.8 million tonnes of GHGs with an intensity of 0.77 tonnes per MWh) were emitted as a result of normal operating activities. Our reduction in GHG emissions is primarily the result of co-firing with gas and lower production volumes at our merchant Alberta coal facilities.

Our 2019 GHG data is reported to a number of different regulatory bodies throughout the year for regional compliance and as a result, may incur minor revisions as we review and report data. Any revisions would be reported historically in future reporting. As per the Kyoto Protocol, GHGs include carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, nitrogen trifluoride, hydrofluorocarbons and perfluorocarbons. Our exposure is limited to carbon dioxide, methane, nitrous oxide and a small amount of sulphur hexafluoride. The majority of our estimated GHG emissions are comprised of carbon dioxide emissions from stationary combustion from coal and natural gas power generation. 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 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 2019 were estimated to be 20.4 million tonnes CO_2e and account for 99 per cent of emissions reported. All of our scope 1 emissions (100 per cent) are reported to national regulatory bodies in the country in which we operate. This includes: Australia (National Greenhouse Gas Emission Reporting), Canada (GHGPR) and the US (EPA). Scope 2 emissions were estimated to be 0.2 million tonnes CO_2e. We estimate our scope 3 emissions to be in the range of six million tonnes.

The following are our GHG emissions broken down by business unit and by scope 1 and 2 in million tonnes CO_2e:

Year ended Dec. 31	**2019**	2018	2017
Coal	**18.1**	18.3	27.4
Gas and renewables	**2.5**	2.5	2.5
Total GHG emissions	**20.6**	**20.8**	**29.9**

Year ended Dec. 31	**2019**	2018	2017
Scope 1	**20.4**	20.6	29.7
Scope 2	**0.2**	0.2	0.2
Total GHG emissions	**20.6**	**20.8**	**29.9**

All of our reported 2019 and historical GHG emissions are verified by Ernst & Young to a level of limited assurance. An assurance statement can be found in the back of this Integrated Annual report. In addition, GHG emissions are verified to a level of reasonable assurance in locations where we operate within a carbon regulatory framework. In Alberta we verify GHG emissions through the TIER program and as a result 51 per cent of our total scope 1 emissions are also verified to a level of reasonable assurance. Our GHG emissions are calculated using a number of different methodologies depending on the technologies available at our facilities.

Our target is to reduce 60 per cent or 19.7 million tonnes of GHG emissions by 2030 over 2015 levels, which is line with UN Sustainable Development Goal Goal 13, Climate Action. Since 2015 we have reduced 11.6 million tonnes, which represents a reduction of 36 per cent. By 2030, we expect to have reduced close to 30 million tonnes over 2005 levels, after adjusting for any new growth over this period.

The following highlights our GHG emission reductions since 2005 and our targeted emissions in 2030 (in line with our GHG target). The actual GHG emissions for the Corporation in 2030 will vary from that presented below depending on, among other things, the growth of the Corporation, including its on-site generation business.

Year ended Dec. 31	**2030**	2019	2005
Total GHG emissions	**12.5**	20.6	41.9

In 2019, 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 most companies in North America. The average CDP score for North America was a C.

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, that we believe provide us with a competitive edge and contribute to shareholder value.

Brand Recognition

Our employee culture is supported by a purpose-based, long-term and sustainable business strategy: growth in affordable and clean electricity 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 electricity strategy, supported by our internal values and sustainable approach to business, will help reinforce and continue to increase our brand recognition positively.

We are a leader in sustainability – publishing our first sustainability report in 1994. We are the first company in Alberta to combine our sustainability report with our financial report and we have been recognized by EXCEL Partnership for demonstrating best-in-class examples in sustainability reporting. Being members of working groups such as the EXCEL Partnership, the Energy Sector Sustainability Leadership Initiative, Canadian Electricity Association Steering Committee and Future-Fit provides validation and support with our sustainability strategy. We are listed on many of these organizations' websites, which further increases awareness of our sustainability practices. In addition, in early 2020, TransAlta was one of 325 companies globally to be added to the Bloomberg Gender-Equality Index. We believe that as we continue to invest in and strengthen our sustainability initiatives, the association of the TransAlta brand with sustainability will increase.

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 over 30 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, natural 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	108
Natural Gas	69
Coal	69
Wind	17
Solar	4

Innovation: Idea Generation and Project Management

As innovation continues to disrupt and advance the global marketplace, we believe that our business, employees, systems and processes must remain competitive, agile and adaptive. Project Greenlight has been a key driver in ensuring the Corporation continues to provide year-over-year improvements in these areas. The program is focused on bottom-up innovation, which means ideas are generated by employees. Emphasizing bottom-up innovation across the Corporation has resulted in a strong culture of idea generation, where employee ideas are developed and advanced into business cases, adhering to project management best practices to ensure the delivery and success of the initiative.

For further details on our investment in our workforce, please see the Talent and Employee Development discussion in the Human Capital section 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. 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 that monitors, to the second, 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 goal to be a leading clean power company 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 projects recently completed in the US and the 207 MW Windrise wind project in Alberta. We have also announced the construction of our SemCAMS Cogeneration Project. Cogeneration is recognized by regulatory bodies for its efficiency in generating power compared to traditional methods. It reduces the natural gas required for several industrial processes by using high-efficiency steam production rather than boilers. The distributed system also provides independence from the power grid and avoids the need to construct additional transmission lines.

Battery storage is another technology we are investing in. TransAlta will begin construction on Alberta's first utility-scale lithium-ion battery storage facility in March 2020, called WindCharger. This project is unique as it will use TransAlta's existing Summerview Wind Farm to charge the battery, allowing WindCharger to be a truly renewable battery energy storage system. The project will use Tesla technology and will have a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. TransAlta will receive co-funding for this project from Emissions Reduction Alberta. Commercial Operation for WindCharger will begin in June 2020. The potential exists for the expansion of this technology, and TransAlta is continually investigating the viability of battery storage at our various wind farm locations.

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. This 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 US 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 to 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. This support is critical to reliability and performance of our operations. By way of example, if a wind turbine starts to underperform compared to the others, our operation team is notified and will work to investigate and remedy the issue. 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.

Data & Innovation

TransAlta created the Data & Innovation team in 2019 for the purpose of modernizing its data infrastructure and processes to take advantage of new opportunities in analytics and artificial intelligence. The Data & Innovation team is cross-functional, composed of data architects, data scientists, data analysts, software developers, engineers, project managers, and financial and systems analysts. The team focuses its efforts on the delivery and enhancement of TransAlta's Modern Data Architecture, the rapid delivery of data-driven applications, the design and implementation of machine learning and artificial intelligence models and the advancement of process automation through the Robotic Process Automation Centre of Excellence.

2019 Sustainability Performance

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.

	Human and Intellectual	Results	Comments
1. Reduce safety incidents	Achieve an Injury Frequency Rate (IFR) below 0.43	Not Achieved	In 2019, our IFR was 0.58. We did not achieve our goal in 2019, but continue to evolve our safety culture and practice. In 2020 we will move away from IFR to strengthen our safety progress. In addition to reporting on TIF, we are also tracking Total Recordable Injury Frequency (TRIF). TRIF tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked. TRIF provides us with the opportunity to target and monitor our significant injuries. It is also an industry-recognized safety metric and allows us to compare and benchmark our safety performance to that of our peers.
	Achieve a Total Injury Frequency (TIF) rate below 1.58	Achieved	In 2019, we achieved a TIF of 1.12 compared to 1.91 in 2018. This decrease was a direct result of our back to basics approach with respect to safety. Specifically, we focused on hazard identification (including audits and inspections), housekeeping and improved contractor management practices across the fleet.

	Natural	Results	Comments
2. Minimize fleet-wide environmental incidents	Keep recorded incidents (including spills and air infractions) below five	Not achieved	In 2019, we recorded nine environmental incidents, which was above our target. We continue to target progress in this area and have divided our environmental incident reporting for 2020 into two categories: significant environmental incidents and non-compliance environmental incidents. We define non-compliance environmental incidents as events that involved a non-compliance event but did not have an impact on the environment. In 2019 only three of our nine recorded environmental incidents had a direct environmental impact. Further information on these incidents can be found in the Environmental Incidents and Spills section in the Natural Capital section in this MD&A.
3. Increase mine reclaimed acreage	Replace annual topsoil at Highvale mine at a rate of 110 acres/year	Achieved	In 2019, as part of ongoing reclamation activities at our Highvale mine, we replaced 114.9 acres of topsoil.

4. Reduce air emissions	Achieve a 95 per cent reduction from 2005 levels of TransAlta SO_2 emissions and 50 per cent reduction in NO_x emissions by 2030	On track	We are well on track to achieve our target of 95 per cent emission reductions of SO_2 and NO_x by 2030. Since 2005, we have reduced NO_x emissions by 61 per cent and SO_2 emissions by 77 per cent. In 2019 we reduced approximately 2,000 tonnes of NO_x emissions and 3,500 tonnes of SO_2 emissions over 2018 levels.
5. Reduce GHG emissions Our GHG goal and targets support UN Sustainable Development Goal 13: Climate Action related to ensuring "integration of 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)	On track	We are well on track to achieve our target of 60 per cent GHG emission reductions by 2030. Since 2015, we have reduced GHG emissions by 36 per cent. In 2019, we reduced approximately 0.2 million tonnes of CO_2e over 2018 levels.

	Social and Relationship	Results	Comments
6. Support quality education for youth Our education goal and target support UN Sustainable Development Goal 4: Quality Education related to ensuring "inclusive and equitable quality education" and related to "eliminating gender disparities in education"	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	Achieved	Support in 2019 included: provided bursaries to high school graduates through a partnership with Indspire, funded academic upgrading programs through SAIT, supported an Indigenous Leadership Program and maintained communication on employment opportunities through various mediums to support different access options for Indigenous communities.

	Comprehensive	Results	Comments
7. TransAlta will be a leading clean power company by 2025	Convert at least two coal units at Sundance, Alberta and three coal units at Keephills, Alberta to gas-fired generation between 2020 and 2023	On track	Progress in 2019 included: completed construction of our Pioneer Pipeline and transported our first gas to both Sundance and Keephills; agreed to purchase two 230 MW Siemens gas turbines to repower Sundance 5; and we announced our Clean Energy Investment Plan, which includes capital investments in our coal-to-gas conversions.
Our clean power goal and targets support the UN Sustainable Development 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)	On track	We continued with our coal-to-gas transition plans in 2019, while announcing new renewable energy growth projects.
	Seek new opportunities to grow our renewable portfolio of 2,265 MW wind, hydro and solar assets	On track	In 2019, we announced an agreement to purchase a 49 per cent interest in the 136.8 MW Skookumchuk wind project

2020 Sustainable Development Targets

Our 2020 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:

ESG Alignment: Environment		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Minimize fleet-wide environmental incidents	Keep annual significant environmental incidents below two and keep environmental regulatory non-compliance incidents below four	Future-Fit Target BE08: "Operations do not encroach on ecosystems or communities"
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	Future-Fit Target PP13: "Ecosystems are restored"
Reduce air emissions	By 2030, achieve a 95% reduction of SO_2 emissions and a 50% reduction of NO_x emissions below 2005 levels from TransAlta coal facilities	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
Reduce GHG emissions	By 2030, achieve company-wide GHG reductions of 60% below 2015 levels, in line with a commitment to the UN SDGs and prevention of 2°C of global warming	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning"
ESG Alignment: Social		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Reduce safety incidents	Achieve a Total Injury Frequency rate below 1.17	UN SDG Target 8.8: "Protect labour rights and promote safe and secure working environments for all workers, including migrant workers, in particular women migrants, and those in precarious employment"
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	UN SDG Target 4.5: "By 2030, eliminate gender disparities in education and ensure equal access to all levels of education and vocational training for the vulnerable, including persons with disabilities, Indigenous peoples and children in vulnerable situations"
ESG Alignment: Governance		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Strengthen gender equality	Achieve a quota of 50 per cent female representation on the Board by 2030 Achieve at least 40 per cent female employment among all employees of the Corporation by 2030 Maintain equal pay for women in equivalent roles as men	UN SDG Target 5.5: "Ensure women's full and effective participation and equal opportunities for leadership at all levels of decision making in political, economic and public life"
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	UN SDG Target 12.6: "Encourage companies, especially large and transnational companies, to adopt sustainable practices and to integrate sustainability information into their reporting cycle"
ESG Alignment: Environment and Social		

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN SDG Target or Future-Fit Target
Leading clean power company by 2025	By the end of 2025, convert coal facilities to gas through boiler conversions and combined-cycle repowering	UN SDG Target 9.4: "By 2030, upgrade infrastructure and retrofit industries to make them sustainable, with increased resource-use efficiency and greater adoption of clean and environmentally sound technologies and industrial processes"
	No further coal generation by the end of 2025 and 100% of our owned net generation capacity will be from clean electricity (renewables and gas)	UN SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services"
	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	UN SDG Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix"

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; they outline 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 AFRC, the Governance, Safety and Sustainability Committee ("GSSC"), the Human Resources Committee (the "HRC") and the Investment Performance Committee ("IPC").

The AFRC, 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 AFRC 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 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 IPC is empowered by the Board to oversee management's investment conclusions and the execution of major, Board-approved capital expenditure projects that further the Corporation's strategic plans. The IPC undertakes a number of actions that include: i) reviewing and considering the substantive risks, returns, financing and other key elements relating to the Corporation's major capital projects; ii) reviewing and assessing mitigation plans, expected outcomes, and implementation throughout the project life cycle with respect to substantive risks; iii) reviewing and assessing cost estimating methodologies employed throughout the project life cycle; iv) reviewing and assessing progress reports including periodic updates on the project schedule, risks and costs at key milestones as projects advance through to execution; v) reviewing post-project look-backs; and vi) reviewing and providing recommendations to the Board regarding capital expenditures associated with such capital projects.

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 Risk and Compliance Committee, and weekly by the commodity risk team, the commercial managers in Trading and Marketing, and the Senior Vice-President Trading & Commercial.

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

The Commodity Risk & Compliance Committee is chaired by our Chief Financial Officer and is comprised of the Chief Financial Officer, Chief Legal, Regulatory & External Affairs Officer, Senior Vice-President Trading & Commercial, and Managing Director Shared Services Finance. 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.

The Hydro Operating Committee consists of two Brookfield members, with expertise in hydro facility management, and and two TransAlta members. This committee was formed in 2019 for the purpose of providing advice and recommendations to TransAlta's management and operational team on matters in connection with the operation, and maximizing the value, of TransAlta's Alberta Hydro Assets. It is delivering on its objectives by thoroughly reviewing the operating, maintenance, safety and environmental aspects of TransAlta's Alberta Hydro Assets and, following that review, providing expert advice and recommendations to TransAlta's hydro operational team. The Committee has an initial term of six years, which can be extended for an additional two years.

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 most recent 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 AFRC, 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 monthly 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 AFRC or through TransAlta's toll-free telephone or online Ethics Helpline. The AFRC Chair is immediately notified of any material complaints and, otherwise, the AFRC 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, 2019, associated with our proprietary commodity risk management activities was $1 million (2018 - $2 million). Refer to the Risk Factors - Commodity Price Risk section of this MD&A below 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 these and other risk factors affecting the Corporation, readers are encouraged to read the Risk Factors section of the AIF, available on our website at www.transalta.com and under our profile on SEDAR at www.sedar.com and on EDGAR at www.edgar.gov.

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

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 2019. 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. The financial performance of our hydro, wind and solar operations is highly dependent upon the availability of their input resources in a given year. Shifts in weather or climate patterns, seasonal precipitation and the timing and rate of melting and runoff may impact the water flow to our facilities. The strength and consistency of the wind resource at our facilities impacts production. The operation of thermal plants can also be impacted by ambient temperatures and the availability of water and fuel. 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	$8 million

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 facilities within defined industry standards that optimizes availability over their commercial operating life;
- Performing preventive maintenance in accordance with applicable industry practices, major equipment supplier recommendations and our operating experience;
- Adhering to comprehensive maintenance programs and regular turnaround schedules;
- Adjusting maintenance plans by facility to reflect equipment type, age and commercial risk;
- Having adequate business interruption insurance in place to cover extended forced outages;
- Having clauses in our PPAs and other long-term contracts that allow us to declare force majeure in the event of an unforeseen failure;
- Selecting and applying proven technology in our generating facilities, where practical;
- Where technology is newer, ensuring service agreements with equipment suppliers include appropriate availability and performance guarantees;
- Monitoring our fleet against industry performance to identify issues or advancements that may impact performance and adjusting our maintenance and investment programs accordingly;
- Negotiating strategic supply agreements with selected vendors to ensure key components are readily 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
- Implementing long-term asset management strategies that optimizes the life cycles of our existing facilities and/or identifies replacement requirements for 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 2019, we had approximately 90 per cent (2018 - 85 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 2019, 66 per cent (2018 - 67 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 76 per cent (2018 - 85 per cent) of our purchased coal was 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 contract durations and from different 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.

Natural Gas Supply and Price Risk

Having sufficient natural gas and natural gas transportation services available so that we can blend natural gas in with coal at our Alberta thermal facilities, and for the ultimate conversion of those units to natural gas is essential to maintaining the reliability and availability of those facilities. Using natural gas at our coal-fired plants, and ultimately converting them to natural gas, allows us to reduce overall carbon emissions and costs, reduce the risk of coal opacity issues, and improves our operating and sustaining capital costs. Ensuring adequate pipeline transportation service and natural gas supply for our Alberta thermal units may be impacted by, among other things, the timing of receiving regulatory and other approvals for firm transportation commitments, weather-related events, work stoppages, system maintenance, variability in pipeline hydraulics pressure and flows, and impacts due to other naturally created events. Pricing of natural gas is driven by market supply and demand fundamentals for natural gas in North America and globally. We are exposed to changes in natural gas prices, which may impact the profitability of our facilities and how the facilities are dispatched into the market.

We manage gas supply and price risk by:

- Ensuring that we have at least two pipelines supplying the gas used in electrical generation in Alberta;
- Contracting for firm gas delivery and supply;
- Monitoring the financial viability of gas producers and pipelines;
- Hedging gas price exposure;
- Monitoring pipelines maintenance schedules and transportation availability; and
- Incorporating the ability to continue using coal in some of the units as the units transition from coal to 100 per cent natural gas.

Environmental Compliance Risk

Environmental compliance risks are risks to our business associated with existing and/or changes in environmental regulations. New emission reduction objectives for the power sector are being established by governments in Canada and the 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_2, and NO_x, which will be adjusted as regulations are finalized;
- Purchasing emission reduction offsets;
- Investing in renewable energy projects, such as wind, solar and hydro generation; and
- Incorporating change-in-law provisions in contracts that allow recovery of certain compliance costs from our customers.

We strive to be in compliance with all environmental regulations relating to operations and facilities. Compliance with both regulatory requirements and management system standards is regularly audited through our performance assurance policy and results are reported quarterly to the 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, 2018. We had no material counterparty losses in 2019. 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, 2019:

	Investment grade *(%)*	**Non-investment grade** *(%)*	**Total** *(%)*	**Total amount**
Trade and other receivables[1]	85	15	**100**	**462**
Long-term finance lease receivables	100	—	**100**	**176**
Risk management assets[1]	99	1	**100**	**806**
Loan receivable[2]	—	100	**100**	**47**
Total				**1,491**

(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 $5 million (2018 - $13 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 and 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 $0.03 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	$0.03	$24 million

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. Credit ratings facilitate these activities and changes in credit ratings may affect our ability and/or the cost of accessing capital markets, 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 impact 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 continue to focus on maintaining our financial position and flexibility. 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, 2019, we have liquidity of $1.7 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2020.

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 AFRC;
- Maintaining a strong balance sheet; 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 to ensure efficiency.

At Dec. 31, 2019, approximately 11 per cent (2018 - 14 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	20	$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 follow established corporate processes and policies;
- Identifying key risks during every stage of project development and ensuring mitigation plans are factored into capital estimates and contingencies;
- Reviewing project plans, key assumptions and returns with senior management prior to Board of Director approvals;
- Consistently applying project management methodologies and processes;
- Determining contracting strategies that are consistent with the project scope and scale to ensure key risks, such as labour and technology, are managed by contractors and equipment suppliers;
- Ensuring contracts for construction and major equipment include key terms for performance, delays and quality backed by appropriate levels of liquidated damages;
- Reviewing projects after achieving commercial operation to ensure learnings are incorporated into the next project;
- Negotiating contracts for construction and major equipment to lock-in key terms such as price, availability of long lead equipment, foreign currency rates and warranties as much as is economically feasible before proceeding with the project; and
- Entering into labour agreements to provide security around labour cost, supply 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 2019, 46 per cent (2018 - 50 per cent) of our labour force was covered by 10 (2018 - 10) collective bargaining agreements. In 2019, four (2018 - four) agreements were renegotiated. We anticipate the successful negotiation of six collective agreements in 2020.

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 a capacity market for electricity in Ontario, potential market bid mitigation in Alberta, uncertainties associated with the development of carbon pricing policies and the qualification of our renewable facilities in Alberta to generate tradable GHG allowances as part of the transition from the *Carbon Competitiveness Incentive Regulation* to the *Technology Innovation and Emissions Reduction* regulations.

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 is 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 partnerships and the payment of funds by our subsidiaries and partnerships in the form of distributions, loans, dividends or otherwise. In addition, our subsidiaries and partnerships 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 that we have in place 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. TransAlta's cybersecurity model consists of three pillars: technology, processes and resourcing. Each of these pillars can be reinforced independently to address specific cyber risks and threats that are confronting TransAlta. Significant cyber risks that could pose a threat to TransAlta include phishing, ransomware, social engineering, supplier chain, commodity hostage, state sponsored, artificial intelligence, machine learning attacks and a high risk of cybersecurity employee turnover. Proactive controls and safeguards to mitigate cybersecurity risk and threats posed to the organization include:

- Leveraging in place technologies to restrict communication within TransAlta's networks thus limiting the ability for adversaries to achieve their aim;
- Partnering with a third-party cybersecurity specialty firm to outsource critical components of our cybersecurity program;
- Enhancing our policies and processes through the use of periodic reviews and table-top exercises;
- Maintaining an effective and robust cybersecurity awareness training and campaign;
- Integrating cybersecurity into our business processes and performing robust cybersecurity risk assessments; and
- Continuously improving our cybersecurity program to ensure it is effective in responding to and addressing cybersecurity risks.

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	$2 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. Refer to the Other Consolidated Analysis section of this MD&A for further details.

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, 2019. 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.

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, 2019, 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 is recorded, processed, summarized and reported within the time frame specified in applicable 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 applicable 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, 2019, the end of the period covered by this report, our ICFR and DC&P were effective.

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

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

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

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

Dawn L. Farrell
President and Chief Executive Officer
Mar. 3, 2020

Todd Stack
Chief Financial Officer

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

The following report is provided by management in respect of TransAlta Corporation's ("TransAlta") internal control over financial reporting (as defined in Rules 13a-15f and 15d-15f under the United States *Securities Exchange Act of 1934* and *National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings).*

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

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

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

TransAlta proportionately consolidates the accounts of the Sheerness, Pioneer Pipeline and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2019 Consolidated Financial Statements of TransAlta included $359 million and $326 million of total and net assets, respectively, as of Dec. 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2019, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2019, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell	**Todd Stack**
President and Chief Executive Officer	Chief Financial Officer

Mar. 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2019 and 2018, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2019, and the related notes and our report dated March 3, 2020 expressed an unqualified opinion thereon.

Basis for Opinion

TransAlta Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on TransAlta Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to TransAlta Corporation in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations, which are included in the 2019 consolidated financial statements of TransAlta Corporation and constituted $359 million and $326 million of total and net assets, respectively, as of December 31, 2019, and $238 million and $133 million of revenues and net earnings, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness, Pioneer Pipeline, and Genesee Unit 3 joint operations.

Ernst & Young LLP

Chartered Professional Accountants
Calgary, Canada
March 3, 2020

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements
We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Corporation") as of December 31, 2019 and 2018, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows, for each of the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Adoption of IFRS 16
As discussed in Note 3 to the consolidated financial statements, the Corporation changed its method of accounting for leases in 2019 due to the adoption of *IFRS 16 - Leases*.

Report on Internal Control Over Financial Reporting
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 3, 2020 expressed an unqualified opinion thereon.

Basis for Opinion
These consolidated financial statements are the responsibility of TransAlta Corporation's management. Our responsibility is to express an opinion on TransAlta Corporation's consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to TransAlta Corporation in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters
The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Long-lived Assets within the US Coal segment & Goodwill related to the Wind and Solar segment

Description of the Matter

As disclosed in notes 2(I), (J), 7, 17, and 20 of the consolidated financial statements, the Corporation owns significant power generation assets which are required to be reviewed for indicators of impairment or impairment reversal at the cash generating unit ("CGU") level and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually. Long lived assets for the US Coal segment amount to $352 million. Goodwill related to the Wind and Solar segment amounts to $176 million.

We identified the assessment of indicators of impairment or impairment reversal for the CGUs within the US Coal segment as a critical audit matter because it involves auditing the judgment applied by management to assess various external and internal sources of information, more specifically if significant changes with an adverse effect on the Corporation have taken place during the year, or will take place in the near future, in the market or economic environment. Determining the recoverable amount for those CGUs for which indicators of impairment or impairment reversal are present within the US Coal segment, as well as determining the recoverable amount for the Wind and Solar segment for the purposes of the annual goodwill impairment test was also identified as a critical audit matter because it involves significant estimation with a high degree of subjectivity including forecasting future cash flows, generation profiles, and commodity prices, and determining the appropriate discount rate.

How We Addressed the Matter in Our Audit

We obtained an understanding of management's process for performing their assessment of indicators of impairment or impairment reversal and the estimation of the recoverable amount. We evaluated the design and tested the operating effectiveness of controls over the Corporation's processes to identify indicators and determine the recoverable amount. Our audit procedures to test the indicators assessment included, among others, evaluating the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. Our audit procedures to test the Corporation's recoverable amount of various CGUs included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical power generation data to evaluate future generation forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Corporation's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking against available market views.

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(Y)(IV) and 14 of the consolidated financial statements, the Corporation enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as Level III are determined using assumptions that are not readily observable. As at December 31, 2019 the Corporation's derivative financial instruments classified as level III were $686 million.

How We Addressed the Matter in Our Audit

Auditing the determination of fair value of level III derivative instruments that rely on significant unobservable inputs can be complex and relies on judgments and estimates concerning future commodity prices, volatility, unit availability, demand profiles, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.

We obtained an understanding of the Corporation's processes and we evaluated and tested the design and operating effectiveness of internal controls addressing the determination and review of inputs used in establishing level III fair values. Our audit procedures included, among others, testing a sample of level III derivative instrument internal models used by management and evaluating the significant assumptions utilized. We also utilized third-party data to test management's future pricing assumptions, credit valuation adjustments, and liquidity assumptions as well as comparing terms such as volumes and timing to executed commodity contracts. We performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of level III fair value. For a sample of new level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates.

Ernst + Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947
Calgary, Canada
March 3, 2020

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2019**	2018	2017
Revenues (Note 5)	**2,347**	2,249	2,307
Fuel, carbon compliance and purchased power (Note 6)	**1,086**	1,100	1,016
Gross margin	**1,261**	1,149	1,291
Operations, maintenance and administration (Note 6)	**475**	515	517
Depreciation and amortization	**590**	574	635
Asset impairment charge (Note 7)	**25**	73	20
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	**(88)**	—	—
Taxes, other than income taxes	**29**	31	30
Termination of Sundance B and C PPAs (Note 4(E))	**(56)**	(157)	—
Net other operating income (Note 9)	**(49)**	(47)	(49)
Operating income	**335**	160	138
Finance lease income	**6**	8	54
Net interest expense (Note 10)	**(179)**	(250)	(247)
Foreign exchange loss	**(15)**	(15)	(1)
Gain on sale of assets and other (Note 4(D) and 17)	**46**	1	2
Earnings (loss) before income taxes	**193**	(96)	(54)
Income tax expense (recovery) (Note 11)	**17**	(6)	64
Net earnings (loss)	**176**	(90)	(118)
Net earnings (loss) attributable to:			
TransAlta shareholders	**82**	(198)	(160)
Non-controlling interests (Note 12)	**94**	108	42
	176	(90)	(118)
Net earnings (loss) attributable to TransAlta shareholders	**82**	(198)	(160)
Preferred share dividends (Note 27)	**30**	50	30
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Weighted average number of common shares outstanding in the year *(millions)*	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 26)	**0.18**	(0.86)	(0.66)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Net earnings (loss)	**176**	(90)	(118)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax[(1)]	**(26)**	15	(6)
Losses on derivatives designated as cash flow hedges, net of tax	**—**	—	(1)
Total items that will not be reclassified subsequently to net earnings	**(26)**	15	(7)
Gains (losses) on translating net assets of foreign operations, net of tax	**(59)**	84	(80)
Reclassification of translation gains on net assets of divested foreign operations[(2)]	**—**	—	(9)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[(3)]	**21**	(41)	50
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax[(4)]	**—**	—	14
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(5)]	**61**	(8)	214
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(6)]	**(42)**	(46)	(107)
Total items that will be reclassified subsequently to net earnings	**(19)**	(11)	82
Other comprehensive income (loss)	**(45)**	4	75
Total comprehensive income (loss)	**131**	(86)	(43)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**54**	(210)	(74)
Non-controlling interests (Note 12)	**77**	124	31
	131	(86)	(43)

(1) Net of income tax recovery of $7 million for the year ended Dec. 31, 2019 (2018 - $5 million expense, 2017 - $(4) million recovery).
(2) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $11 million expense).
(3) Net of income tax expense of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $2 million expense).
(4) Net of reclassification of income tax of nil for the year ended Dec. 31, 2019 (2018 - nil, 2017 - $2 million recovery).
(5) Net of income tax expense of $16 million for the year ended Dec. 31, 2019 (2018 - $1 million recovery, 2017 - $77 million recovery).
(6) Net of reclassification of income tax expense of $10 million for the year ended Dec. 31, 2019 (2018 - $11 million expense, 2017 - $31 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018
Cash and cash equivalents	**411**	89
Restricted cash (Note 23)	**32**	66
Trade and other receivables (Note 13)	**462**	756
Prepaid expenses	**19**	13
Risk management assets (Note 14 and 15)	**166**	146
Inventory (Note 16)	**251**	242
	1,341	1,312
Long-term portion of finance lease receivables (Note 8)	**176**	191
Risk management assets (Note 14 and 15)	**640**	662
Property, plant and equipment (Note 17)		
Cost	**13,395**	13,202
Accumulated depreciation	**(7,188)**	(7,038)
	6,207	6,164
Right of use assets (Note 18)	**146**	—
Intangible assets (Note 19)	**318**	373
Goodwill (Note 20)	**464**	464
Deferred income tax assets (Note 11)	**18**	28
Other assets (Note 21)	**198**	234
Total assets	**9,508**	9,428
Accounts payable and accrued liabilities	**413**	496
Current portion of decommissioning and other provisions (Note 22)	**58**	70
Risk management liabilities (Note 14 and 15)	**81**	90
Current portion of contract liabilities (Note 5)	**1**	8
Income taxes payable	**14**	10
Dividends payable (Note 26 and 27)	**37**	58
Current portion of long-term debt and lease obligations (Note 23)	**513**	148
	1,117	880
Credit facilities, long-term debt and lease obligations (Note 23)	**2,699**	3,119
Exchangeable securities (Note 14 and 24)	**326**	—
Decommissioning and other provisions (Note 22)	**488**	386
Deferred income tax liabilities (Note 11)	**472**	501
Risk management liabilities (Note 14 and 15)	**29**	41
Contract liabilities (Note 5)	**14**	80
Defined benefit obligation and other long-term liabilities (Note 25)	**301**	287
Equity		
Common shares (Note 26)	**2,978**	3,059
Preferred shares (Note 27)	**942**	942
Contributed surplus	**42**	11
Deficit	**(1,455)**	(1,496)
Accumulated other comprehensive income (Note 28)	**454**	481
Equity attributable to shareholders	**2,961**	2,997
Non-controlling interests (Note 12)	**1,101**	1,137
Total equity	**4,062**	4,134
Total liabilities and equity	**9,508**	9,428

Significant and subsequent events (Note 4)
Commitments and contingencies (Note 35)

Gordon D. Giffin

On behalf of the Board: Gordon D. Giffin, Director; Beverlee F. Park, Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2017	$3,094	$942	$10	$ (1,209)	$489	$3,326	$1,059	$4,385
Impact of change in accounting policy	—	—	—	(14)	—	(14)	1	(13)
Adjusted balance as at Jan. 1, 2018	3,094	942	10	(1,223)	489	3,312	1,060	4,372
Net earnings (loss)	—	—	—	(198)	—	(198)	108	(90)
Other comprehensive income (loss):								
Net gains on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	43	43	—	43
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(54)	(54)	—	(54)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	15	15	—	15
Intercompany FVOCI investments	—	—	—	—	(16)	(16)	16	—
Total comprehensive income (loss)				(198)	(12)	(210)	124	(86)
Common share dividends	—	—	—	(57)	—	(57)	—	(57)
Preferred share dividends	—	—	—	(50)	—	(50)	—	(50)
Shares purchased under NCIB	(35)	—	—	12	—	(23)	—	(23)
Changes in non-controlling interests in TransAlta Renewables (Note 4(N) and 12)	—	—	—	20	4	24	133	157
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(180)	(180)
Balance, Dec. 31, 2018	3,059	942	11	(1,496)	481	2,997	1,137	4,134
Impact of change in accounting policy (Note 3)	—	—	—	3	—	3	—	3
Adjusted balance as at Jan. 1, 2019	**3,059**	**942**	**11**	**(1,493)**	**481**	**3,000**	**1,137**	**4,137**
Net earnings	**—**	**—**	**—**	**82**	**—**	**82**	**94**	**176**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(38)**	**(38)**	**—**	**(38)**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**19**	**19**	**—**	**19**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(26)**	**(26)**	**—**	**(26)**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**17**	**17**	**(17)**	**—**
Total comprehensive income (loss)				**82**	**(28)**	**54**	**77**	**131**
Common share dividends	**—**	**—**	**—**	**(34)**	**—**	**(34)**	**—**	**(34)**
Preferred share dividends	**—**	**—**	**—**	**(30)**	**—**	**(30)**	**—**	**(30)**
Shares purchased under NCIB	**(83)**	**—**	**—**	**15**	**—**	**(68)**	**—**	**(68)**
Changes in non-controlling interests in TransAlta Renewables	**—**	**—**	**—**	**5**	**1**	**6**	**22**	**28**
Effect of share-based payment plans (Note 29)	**2**	**—**	**31**	**—**	**—**	**33**	**—**	**33**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(135)**	**(135)**
Balance, Dec.31, 2019	**2,978**	**942**	**42**	**(1,455)**	**454**	**2,961**	**1,101**	**4,062**

(1) Refer to Note 28 for details on components of, and changes in, accumulated other comprehensive income (loss).
See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2019**	2018	2017
Operating activities			
Net earnings (loss)	**176**	(90)	(118)
Depreciation and amortization (Note 36)	**709**	710	708
Net gain (loss) on sale of assets (Note 4(D) and 17)	**(45)**	—	(1)
Accretion of provisions (Note 22)	**23**	24	23
Decommissioning and restoration costs settled (Note 22)	**(34)**	(31)	(19)
Deferred income tax recovery (Note 11)	**(18)**	(34)	(15)
Unrealized (gain) loss from risk management activities	**(32)**	30	(48)
Unrealized foreign exchange loss	**13**	28	22
Provisions	**13**	7	(7)
Asset impairment charge (Note 7)	**25**	73	20
Other non-cash items	**(102)**	147	175
Cash flow from operations before changes in working capital	**728**	864	740
Change in non-cash operating working capital balances (Note 32)	**121**	(44)	(114)
Cash flow from operating activities	**849**	820	626
Investing activities			
Additions to property, plant and equipment (Note 17 and 36)	**(417)**	(277)	(338)
Additions to intangibles (Note 19 and 36)	**(14)**	(20)	(51)
Restricted cash (Note 23)	**34**	(35)	(30)
Loan receivable (Note 21)	**(10)**	1	(38)
Acquisitions, net of cash acquired (Note 4)	**(117)**	(30)	—
Investment in the Pioneer Pipeline (Note 4(H))	**(83)**	(15)	—
Proceeds on sale of property, plant and equipment	**13**	2	3
Proceeds on sale of Wintering Hills facility and Solomon disposition (Note 4(T) and 4(X))	**—**	2	478
Income tax expense on Solomon disposition (Note 4(T) and 11)	**—**	—	(56)
Realized gains on financial instruments	**3**	2	6
Decrease in finance lease receivable	**24**	59	59
Other	**23**	13	(3)
Change in non-cash investing working capital balances	**32**	(96)	57
Cash flow from (used in) investing activities	**(512)**	(394)	87
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 23)	**(119)**	312	26
Repayment of long-term debt (Note 23)	**(96)**	(1,179)	(814)
Issuance of long-term debt (Note 23)	**166**	345	260
Issuance of exchangeable securities (Note 24)	**350**	—	—
Dividends paid on common shares (Note 26)	**(45)**	(46)	(46)
Dividends paid on preferred shares (Note 27)	**(40)**	(40)	(40)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4(O))	**—**	144	—
Repurchase of common shares under NCIB (Note 26)	**(68)**	(23)	—
Realized gains on financial instruments	**—**	48	106
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(106)**	(165)	(172)
Decrease in lease obligations (Note 23)	**(21)**	(18)	(17)
Financing fees and other	**(35)**	(31)	(6)
Change in non-cash financing working capital balances	**—**	2	—
Cash flow used in financing activities	**(14)**	(651)	(703)
Cash flow from (used in) operating, investing, and financing activities	**323**	(225)	10
Effect of translation on foreign currency cash	**(1)**	—	(1)
Increase (decrease) in cash and cash equivalents	**322**	(225)	9
Cash and cash equivalents, beginning of year	**89**	314	305
Cash and cash equivalents, end of year	**411**	89	314
Cash income taxes paid	**35**	87	14
Cash interest paid	**185**	188	230

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

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

II. Energy Marketing Segment

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

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

III. Corporate

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

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on Mar. 3, 2020.

C. Basis of Consolidation

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

2. Significant Accounting Policies

A. Revenue Recognition

I. Revenue from Contracts with Customers - 2019 and 2018 Policy

The Corporation adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018.

The Corporation elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and elected to apply IFRS 15 only to contracts that are active at the date of initial adoption. Comparative information has not been restated and is reported under IAS 18 *Revenue* (IAS 18). Refer to section III below for the accounting policy for years prior to 2018.

The majority of the Corporation’s revenues from contracts with customers are derived from the sale of generation capacity, electricity, thermal energy, environmental 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.

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.

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.

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 estimates the amount of the transaction price to allocate to individual performance obligations based on their relative standalone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Recognition
The nature, timing of recognition of satisfied performance obligations and payment terms for the Corporation's goods and services are described below:

Good or Service	***Description***
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (i.e., monthly) in an amount representative of availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract Power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal Energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Environmental Attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
Generation Byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Corporation's Canadian and US coal operations, and the sale of coal to third parties. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the Corporation receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Corporation has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Corporation recognizes unconditional rights to consideration separately as a receivable. Contract assets and receivables are evaluated at each reporting period to determine whether there is any objective evidence that they are impaired.

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.

II. 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 the Corporation retains 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. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

III. Revenue Recognition Policy Prior to 2018
The majority of the Corporation's revenues are derived from the sale of physical power, the leasing of power facilities and from energy marketing and trading activities. Revenues are measured at the fair value of the consideration received or receivable.

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

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

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

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments
Effective Jan. 1, 2018, the Corporation adopted IFRS 9 *Financial Instruments* ("IFRS 9"). In accordance with the transition provisions of the standard, the Corporation elected to not restate prior periods. Refer to section III below for information on its prior accounting policy. The Corporation's accounting policies under IFRS 9 are outlined below.

Classification and Measurement
IFRS 9 introduced the requirement to classify and measure financial assets based on their contractual cash flow characteristics and the Corporation's business model for the financial asset. All financial assets and financial liabilities, including derivatives, are recognized at fair value on the Consolidated Statements of Financial Position when the Corporation becomes party to the contractual provisions of a financial instrument or non-financial derivative contract. Financial assets must be classified and measured at either amortized cost, at fair value through profit or loss ("FVTPL"), or at fair value through other comprehensive income ("FVOCI").

Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows are subsequently measured at amortized cost. Financial assets measured at FVOCI are those that have contractual cash flows arising on specific dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows and to sell the financial asset. All other financial assets are subsequently measured at FVTPL.

Financial liabilities are classified as FVTPL when the financial liability is held for trading. All other financial liabilities are subsequently measured at amortized cost.

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the US where project investors acquire an equity investment in the project entity and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the Corporation then receiving the majority of earnings, cash flows and tax benefits. At that time, the tax equity financings will be classified as a non-controlling interest. In applying the effective interest method to tax equity financings, the Corporation has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Corporation enters into a variety of derivative financial instruments to manage its exposure to commodity price risk, interest rate risk and foreign currency exchange risk, including fixed price financial swaps, long-term physical power sale contracts, foreign exchange forward contracts and designating foreign currency debt as a hedge of net investments in foreign operations.

Derivatives are initially recognized at fair value at the date the derivative contracts are entered into and are subsequently remeasured to their fair value at the end of each reporting period. The resulting gain or loss is recognized in net earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of the recognition in net earnings is dependent on the nature of the hedging relationship.

Derivatives embedded in non-derivative host contracts that are not financial assets within the scope of IFRS 9 (e.g., financial liabilities) are treated as separate derivatives when they meet the definition of a derivative, their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

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

Financial assets are also derecognized when the Corporation has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows to a third party under a "passthrough" arrangement and either transferred substantially all the risks and rewards of the asset, or transferred control of the asset. TransAlta will continue to recognize the asset and any associated liability if TransAlta retains substantially all of the risks and rewards of the asset, or retains control of the asset. Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that TransAlta could be required to repay.

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

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

Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. 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 or if the financial asset is a purchased or originated credit-impaired financial asset. 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.

For trade receivables, lease receivables and contract assets recognized under IFRS 15, TransAlta applies a simplified approach for measuring the loss allowance. Therefore, the Corporation does not track changes in credit risk but instead recognizes a loss allowance at an amount equal to the lifetime expected credit losses at each reporting date.

The assessment of the expected credit loss is based on historical data and adjusted by forward-looking information. Forward-looking information utilized includes third-party default rates over time, dependent on credit ratings.

II. Hedges
Where hedge accounting can be applied and the Corporation chooses to seek hedge accounting treatment, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposures of a net investment in a foreign operation.

A relationship qualifies for hedge accounting if, at inception, it is formally designated and documented as a hedge, and the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. The documentation includes identification of the hedging instrument and hedged item or transaction, the nature of the risk being hedged, the Corporation's risk management objectives and strategy for undertaking the hedge, and how hedge effectiveness will be assessed. The process of hedge accounting includes linking derivatives to specific recognized assets and liabilities or to specific firm commitments or highly probable anticipated transactions.

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

Fair Value Hedges
In a fair value hedging relationship, the carrying amount of the hedged item is adjusted for changes in fair value attributable to the hedged risk, with the changes being recognized in net earnings. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging derivative, which is also recorded in net earnings.

For fair value hedges relating to items carried at amortized cost, any adjustment to carrying value is amortized through profit or loss over the remaining term of the hedge using the effective interest rate ("EIR") method. The EIR amortization may begin as soon as an adjustment exists and no later than when the hedged item ceases to be adjusted for changes in its fair value attributable to the risk being hedged.

If the hedged item is derecognized, the unamortized fair value is recognized immediately in profit or loss.

Cash Flow Hedges
In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in OCI while any ineffective portion is recognized in net earnings. The cash flow hedge reserve is adjusted to the lower of the cumulative gain or loss on the hedging instrument and the cumulative change in fair value of the hedged item.

If cash flow hedge accounting is discontinued, the amounts previously recognized in AOCI must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation
In hedging a foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instrument is recognized in OCI and the ineffective portion is recognized in net earnings. The related fair values are recorded in risk management assets or liabilities, as appropriate. The amounts previously recognized in AOCI are recognized in net earnings when there is a reduction in the hedged net investment as a result of a disposal, partial disposal or loss of control.

III. Financial Instruments and Hedges Accounting Policy Prior to 2018
Financial Instruments
Financial assets and financial liabilities, including derivatives and certain non-financial derivatives, are recognized on the Consolidated Statements of Financial Position when the Corporation becomes a party to the contract. All financial instruments, except for certain non-financial derivative contracts that meet the Corporation's own use requirements, are measured at fair value upon initial recognition. Measurement in subsequent periods depends on whether the financial instrument has been classified as: at fair value through profit or loss, available-for-sale, held-to-maturity, loans and receivables, or other financial liabilities. Classification of the financial instrument is determined at inception depending on the nature and purpose of the financial instrument.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. Emission Credits and Allowances
Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the Corporation are recorded at cost and are carried at the lower of weighted average cost and net realizable value. For emission credits that are not ordinarily interchangeable, the Corporation records the credits using the specific identification method. Credits granted to, or internally generated by, TransAlta are recorded at nil. Emission liabilities are recorded using the best estimate of the amount required by the Corporation to settle its obligation in excess of government-established caps and targets. To the extent compliance costs are recoverable under the terms of contracts with third parties, the amounts are recognized as revenue in the period of recovery.

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

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

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

The cost of routine repairs and maintenance and the replacement of minor parts is charged to net earnings as incurred. Subsequent to initial recognition and measurement at cost, all classes of PP&E continue to be measured using the cost model and are reported at cost less accumulated depreciation and impairment losses, if any.

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

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

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

Coal generation	2-10 years
Pipeline	50 years
Gas generation	2-30 years
Hydro generation	2-60 years
Wind generation	2-30 years
Mining property and equipment	2-10 years
Capital spares and other	2-60 years

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

H. Intangible Assets

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

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

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

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

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

Software	2-7 years
Power sale contracts	1-20 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

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

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

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

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

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

Q. Leases
I. 2019 Lease Policy
The Corporation adopted IFRS 16 *Leases* ("IFRS 16") with an initial adoption date of Jan. 1, 2019. As a result, in 2019, the Corporation changed its accounting policy for leases, which is outlined below. Refer to (II) below for information on the prior accounting policy.

Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration.

Lessee
The Corporation enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Corporation is the lessee, and which are not exempt as short-term or low-value leases, the Corporation:
- Recognizes right of use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right of use assets and interest expense on lease obligations in the Consolidated Statements of Earnings (loss); and
- Recognizes the principal repayments on lease obligations as financing activities and interest payments on lease obligations as operating activities in the Consolidated Statements of Cash Flow.

For short-term and low-value leases, the Corporation recognizes the lease payments as operating expenses.

Variable lease payments that do not depend on an index or a rate are not included in the measurement of the lease liability and the right of use asset and are recognized as an expense in the period in which the event or condition that triggers the payments occurs.

Right of use assets are initially measured at an amount equal to the lease liability and adjusted for any payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset, or to restore the underlying asset or the site on which it is located, less any lease incentives received.

Lease liabilities are initially measured at the present value of the lease payments that are not paid at commencement and discounted using the Corporation's incremental borrowing rate or the rate implicit in the lease. The lease liability is remeasured when there is a change in future lease payments arising from a change in an index or rate, or if there is a change in the Corporation’s estimate or assessment of whether it will exercise an extension, termination, or purchase option. A corresponding adjustment is made to the carrying amount of the right of use asset, or is recorded in profit or loss if the carrying amount of the right of use asset has been reduced to zero.

The lease term includes periods covered by an option to extend if the Corporation is reasonably certain to exercise that option and periods covered by an option to terminate if the Corporation is reasonably certain not to exercise that option.

Right of use assets are depreciated over the shorter period of either the lease term or the useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right of use asset reflects that the Corporation expects to exercise the purchase option, the related right of use asset is depreciated over the useful life of the underlying asset.

The Corporation has elected to apply the practical expedient that permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement.

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

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

Where the Corporation determines that the contractual provisions of a contract contain, or are, a lease and result in the Corporation retaining the principal risks and rewards of ownership of the asset, the arrangement is an operating lease. For operating leases, the asset is, or continues to be, capitalized as PP&E and depreciated over its useful life.

When the Corporation has subleased all or a portion of an asset it is leasing and for which it remains the primary obligor under the lease, it accounts for the head lease and the sublease as two separate contracts. The sublease is classified as a finance lease by reference to the right of use asset arising from the head lease.

II. Lease Policy Prior to 2019
A lease is an arrangement whereby the lessor conveys to the lessee, in return for a payment or series of payments, the right to use an asset for an agreed period of time.

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

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

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

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

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

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

S. Non-Controlling Interests

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

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

T. Joint Arrangements

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

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

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

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

U. Government Incentives

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

V. Earnings per Share

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

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

W. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. A business consists of inputs and processes applied to those inputs that have the ability to contribute to the creation of outputs. Goodwill is measured as the excess of the fair value of consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Acquisition-related costs to effect the business combination, with the exception of costs to issue debt or equity securities, are recognized in net earnings as incurred.

In 2019, the Corporation early-adopted amendments to IFRS 3 *Business Combinations* in advance of the mandatory effective date of Jan. 1, 2020. The amendments, among other things, introduced an optional fair value concentration test that can be applied on a transaction-by-transaction basis, to permit a simplified assessment of whether an acquired set of activities and assets are not a business. Where substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets, the Corporation may elect to treat the acquisition as an asset acquisition and not as a business combination.

X. Stripping Costs

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

Y. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. Impairment of PP&E and Goodwill

Impairment exists when the carrying amount of an asset, CGU or group of CGUs to which goodwill relates exceeds its recoverable amount, which is the higher of its fair value less costs of disposal and its value in use. An assessment is made at each reporting date as to whether there is any indication that an impairment charge may exist or that a previously recognized impairment charge may no longer exist or may have decreased. In determining fair value less costs of disposal, information about third-party transactions for similar assets is used and if none is available, other valuation techniques, such as discounted cash flows, are used. Value in use is computed using the present value of management's best estimates of future cash flows based on the current use and present condition of the asset.

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

Discount rates are determined by employing a weighted average cost of capital methodology that is based on capital structure, cost of equity and cost of debt assumptions based on comparable companies with similar risk characteristics and market data as the asset, CGU or group of CGUs subject to the test. These estimates and assumptions are susceptible to change from period to period and actual results can, and often do, differ from the estimates, and can have either a positive or negative impact on the estimate of the impairment charge, and may be material.

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The Corporation evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Corporation's own commodity price risk management plans and practices, in order to inform this determination.

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2017 to 2019 is found in Notes 7, 17 and 20.

II. Leases
In determining whether the Corporation's contracts contain, or are, leases, management must use judgment in assessing whether the contract provides the customer with the right to substantially all of the economic benefits from the use of the asset during the lease term and whether the customer obtains the right to direct the use of the asset during the lease term. For those agreements considered to contain, or be, leases, further judgment is required to determine the lease term by assessing whether termination or extension options are reasonably certain to be exercised. Judgment is also applied in identifying in-substance fixed payments (included) and variable payments that are based on usage or performance factors (excluded) and in identifying lease and non-lease components (services that the supplier performs) of contracts and in allocating contract payments to lease and non-lease components.

For leases where the Corporation is a lessor, judgment is required to determine if substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes
Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. See Note 11 for further details on the impacts of the Corporation's tax policies.

IV. Financial Instruments and Derivatives

The Corporation’s financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Corporation’s fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

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

When the Corporation enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Corporation must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Corporation's expected purchase, sale or usage requirements (i.e. normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Corporation considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate, and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion.

V. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized. Information on the write-off of project development costs is disclosed in Note 7.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 22. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation’s best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2019 in respect of decommissioning and restoration provisions can be found in Note 3(A)(IV) and Notes 7 and 22.

VII. Useful Life of PP&E

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

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 30 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, the Corporation recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 22 with respect to other provisions.

X. Revenue from Contracts with Customers
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 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.

In determining the transaction price and estimates of variable consideration, management considers past history of customer usage 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. 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.

The satisfaction of performance obligations requires management to make judgments 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 permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements
Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, which classification affects the accounting for the joint arrangement. In making this classification, the Corporation exercises judgment in evaluating the terms and conditions of the arrangement to determine whether the parties have rights to the assets and obligations or rights to the net assets. Factors such as the legal structure, contractual arrangements and other facts and circumstances, such as where the purpose of the arrangement is primarily for the provision of the output to the parties and when the parties are substantially the only source of cash flows for the arrangement, must be evaluated to understand the rights of the parties to the arrangement.

3. Accounting Changes

A. Current Accounting Changes

I. IFRS 16 *Leases*

The Corporation adopted IFRS 16 with an initial adoption date of Jan. 1, 2019. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. The standard provides a single lessee accounting model, requiring lessees to recognize a right of use asset and liabilities for all in-scope leases. Under IFRS 16, a contract contains a lease when the customer obtains the right to control the use of an identified asset for a period of time in exchange for consideration. Previously, the Corporation determined at contract inception whether an arrangement is or contains a lease under IAS 17 *Leases* ("IAS 17") or International Financial Reporting Interpretations Committee Interpretation 4 *Determining Whether an Arrangement Contains a Lease*.

The Corporation elected to adopt IFRS 16 using the modified retrospective approach on transition. The Corporation applied the definition of a lease and related guidance set out in IFRS 16 to all lease contracts in existence at Dec. 31, 2018. All relevant contractual arrangements outstanding at that date were reviewed to assess if the contract meets the new definition of a lease.Comparative information has not been restated and is reported under IAS 17. Refer to Note 2(Q)(II) for details on the accounting policy in prior years.

The Corporation recognized the cumulative impact of the initial application of the standard of $3 million in deficit as at Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation used the following practical expedients permitted by the standard:

- Exemption to not recognize right of use assets and lease liabilities for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019, and for low value leases;
- Excluded initial direct costs from the measurement of the right of use asset at the date of initial application;
- Used hindsight to determine the lease term where the contract contained options to extend or terminate the lease;
- Adjusted the right of use assets by the amount relating to onerous contract provisions as defined under IAS 37 *Provisions, contingent liabilities and contingent assets* ("IAS 37") immediately before the date of initial application; and
- Measured the right of use asset at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments related to that lease that was recognized in the statement of financial position immediately before the date of initial application.

Impact on the Financial Statements

Lessee

The Corporation recognized the cumulative impact of the initial application of the standard by recording a right of use asset based on the corresponding lease liability measured at the present value of the remaining lease payments discounted using the Corporation's incremental borrowing rate (or the rate implicit in the lease) applied to the lease liabilities at Jan. 1, 2019. The weighted average incremental borrowing rate applied to the lease liabilities on Jan. 1, 2019, was 5.71 per cent.

The following table reconciles the Corporation's operating lease commitments at Dec. 31, 2018, as previously disclosed in the Corporation's 2018 annual consolidated financial statements, to the lease obligations recognized on initial application of IFRS 16 and included in credit facilities, long-term debt and lease obligations on the Consolidated Statements of Financial Position as at Jan. 1, 2019:

Non-cancellable operating lease commitments disclosed at Dec. 31, 2018	80
Less: Exemption for low-value leases	(1)
Add: Extension and termination options reasonably certain to be exercised	4
Undiscounted lease liability	83
Discounted using the incremental borrowing rate at Jan. 1, 2019	(31)
New lease liabilities recognized as at Jan. 1, 2019	52
Add: 2018 finance lease obligations	63
Less: 2018 finance lease obligations that do not meet the IFRS 16 definition of a lease	(32)
Lease liabilities as at Jan. 1, 2019	**83**

The associated right of use assets were measured at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements. On Jan. 1, 2019, the Corporation recognized right of use assets of $85 million, including $38 million that was previously included in PP&E, intangible assets and other assets.

Applying the IFRS 16 definition of a lease 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 resulted in the derecognition of a finance lease asset of $29 million and a finance lease liability of $32 million with the net impact of $3 million recorded in deficit.

Lessor
Several of the Corporation's long-term contracts at certain wind, hydro and solar facilities are no longer considered to be operating leases under IFRS 16. Revenues earned on these contracts are now accounted for applying IFRS 15 *Revenue from Contracts with Customers*. No significant change in the pattern of revenue recognition arose. The Corporation continues to account for its subleases as operating leases.

For further details on the lease policy under IFRS 16, refer to Note 2(Q)(I) and to Note 18 for a summary of the Corporation's leases.

II. IFRS 3 Business Combinations
Effective Oct. 1, 2019, the Corporation early-adopted amendments to IFRS 3 *Business Combinations* ("IFRS 3 amendments"), in advance of its mandatory effective date of Jan. 1, 2020. The Corporation adopted the IFRS 3 amendments prospectively and therefore the comparative information presented for 2018 has not been restated. The IFRS 3 amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. Specifically, these amendments:

- Clarify the minimum requirements for a business, whereby at minimum, an input and a substantive process that together significantly contribute to the ability to create output must be present;
- Remove the assessment of whether market participants are capable of replacing any missing elements so that the assessment is based on what has been acquired in its current state and condition, rather than on whether market participants are capable of replacing any missing elements, for example, by integrating the acquired activities and assets;
- Add guidance to help entities assess whether an acquired process is substantive, which requires more persuasive evidence when there are no outputs, because the existence of outputs provides some evidence that the acquired set of activities and assets is a business;
- Narrow the definition of outputs to focus on goods or services provided to customers, investment income or other income from ordinary activities; and
- Introduce an optional fair value concentration test that can be applied on a transaction-by-transaction basis to permit a simplified assessment of whether an acquired set of activities and assets are not a business. The concentration test is met if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets.

The Corporation elected to apply the optional fair value concentration test to its acquisition of the remaining 50 per cent interest in Keephills 3 (refer to Note 4(D) for further details). There are no other impacts to the asset acquisitions that were completed during the year ended Dec. 31, 2019.

III. IFRIC 23 - Uncertainty over Income Tax Treatments
The Corporation adopted IFRIC *23 Uncertainty over Income Tax Treatments* on its effective date of Jan. 1, 2019 and applied it retrospectively. No cumulative effect of initially applying the guidance arose. The Interpretation clarifies the application of recognition and measurement requirements in IAS 12 *Income Taxes* when there is uncertainty over income tax treatments and provides guidance on: considering uncertain tax treatments separately or together; examination by tax authorities; the appropriate method to reflect uncertainty; and accounting for changes in facts and circumstances.

IV. Change in Estimates
Canadian Coal
During the third quarter of 2019, the Corporation adjusted the useful lives of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see Note 4(A) for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019 increased by approximately $16 million.

In 2018, as a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 9(A), the Corporation adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. In addition, on Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2018, increased by approximately $38 million (2017 - $58 million). The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (refer to Note 7 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, 2019. 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 Minister of Environment & Climate Change agreed to extend the useful life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the useful 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. However, in the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment charge for the remaining net book value of the asset (refer to Note 7 for further details).

Wind and Solar
During the third quarter of 2019, the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components were reviewed. As a result of the review, additional components were identified for parts where the useful lives are shorter than the original estimate. The useful life of each of these components was reduced from 30 years to either 15 years or 10 years. Accordingly, depreciation expense for the year ended Dec. 31, 2019 increased by approximately $11 million.

Sheerness
During the second quarter of 2019, the Corporation adjusted the useful life of its Sheerness coal-fired plant assets to align with the dual-fuel conversion plans. As a result, the assets used for coal-burning operations as well as the other asset lives were extended and depreciation expense for the year ended Dec. 31, 2019 decreased by approximately $8 million.

The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events.

Centralia
During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will be completed as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

TransAlta estimates that the undiscounted amount of cash flow required to settle this additional obligation is approximately $222 million, which will be incurred between 2021 and 2035. The provision may be revised in compliance with the Corporation's accounting policies, dependent upon future operating decisions and as more information becomes available.

B. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

4. Significant and Subsequent Events

A. Clean Energy Investment Plan

On Sept. 16, 2019, TransAlta announced its Clean Energy Investment Plan, which includes converting its existing Alberta coal assets to natural gas and advancing its leadership position in onsite generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017.

TransAlta's plan includes converting three of its existing Alberta thermal units to gas in 2020 and 2021 by replacing existing coal burners with natural gas burners. As discussed further below in this section, the Corporation is also advancing permitting to convert one, or possibly two, of its units to highly efficient combined-cycle natural gas units. The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost generator in the Alberta energy-only market;
- Generating attractive returns by leveraging the Corporation's existing infrastructure;
- Significantly extending the life and cash flows of the Alberta thermal assets; and
- Significantly reducing air emissions and costs.

On Oct. 30, 2019, TransAlta acquired two 230 MW Siemens F class gas turbines and related equipment for $84 million. These turbines will be redeployed to TransAlta's Sundance site as part of the strategy to repower Sundance Unit 5 to a highly efficient combined-cycle unit. TransAlta expects to issue Limited Notice to Proceed ("LNTP") in 2020 and Full Notice to Proceed ("FNTP") in 2021 for the Sundance Unit 5 repowering, with an expected commercial operation date in 2023. The Sundance Unit 5 repowered combined-cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $750 million to $770 million. In conjunction with the Sundance Unit 5 permitting, TransAlta is also permitting Keephills Unit 1 to maintain the option to repower Keephills Unit 1 to a combined-cycle unit, depending on market fundamentals. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of greenhouse gas ("GHG") costs, starting in late 2023 with Shell Energy North America (Canada).

The Corporation's Clean Energy Investment Plan also consists of three wind projects in the United States, one wind project in Alberta and a cogeneration facility. The Big Level and Antrim wind projects began commercial operations on Dec. 19, 2019 and Dec, 24, 2019, respectively. The Skookumchuck and Windrise wind projects are currently under construction. These projects are underpinned by long-term PPAs with highly creditworthy counterparties. In addition, TransAlta is currently constructing a cogeneration facility which will be jointly owned, operated and maintained with SemCAMS.

B. Acquisition of Wind Development Projects

During 2019, TransAlta acquired a portfolio of wind development projects in the US. If the Corporation decides to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025.

C. Agreement to Construct and Own a Cogeneration Plant in Alberta

On Oct. 1, 2019, TransAlta and SemCAMS Midstream ULC ("SemCAMS") announced that they had entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The Kaybob facility is strategically located in the Western Canadian Sedimentary Basin and accepts natural gas production out of the Montney and Duvernay formations. TransAlta will construct the cogeneration plant, which will be jointly owned, operated and maintained with SemCAMS. The capital cost of the new cogeneration facility is expected to be approximately $105 million to $115 million and the project is expected to deliver approximately $18 million in annual EBITDA. TransAlta will be responsible for all capital costs during construction and, subject to the satisfaction of certain conditions, SemCAMS is expected to purchase a 50 per cent interest in the new cogeneration facility as of the commercial operation date, which is targeted for late 2021.

All of the steam production and approximately half of the electricity output will be contracted to SemCAMS under a 13-year fixed price contract. The remaining electricity generation will be sold into the Alberta power market by TransAlta. The agreement contemplates an automatic seven-year extension subject to certain termination rights.

D. TransAlta and Capital Power Swap Non-Operating Interests in Keephills 3 and Genesee 3

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the 466 MW Genesee 3 facility for Capital Power's 50 per cent ownership interest in the 463 MW Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

The transaction price for each non-operating interest largely offset each other, resulting in a net payment of approximately $10 million from Capital Power to TransAlta. Final working capital true-ups and settlements occurred in November 2019, with a net working capital difference of less than $1 million paid by TransAlta to Capital Power.

As discussed in Note 3(A)(II), the Corporation early-adopted 2020 amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test. The Corporation elected to apply the optional fair value concentration test to its acquisition of the non-operating interest in Keephills 3, through which it was determined that greater than 90 per cent of the fair value was concentrated in the PP&E acquired. As a result, the acquisition was determined to not be a business and IFRS 3 requirements were not applied and the existing carrying amount of the owned 50 per cent of Keephills 3 was not required to be assessed at fair value. Consequently, the acquisition has been accounted for as an asset acquisition, with the following carrying amounts assigned based on relative fair values:

Working capital	11
Property, plant and equipment	308
Other assets	3
Other liabilities	(2)
Decommissioning and other provisions	(19)
Total acquisition cost	**301**

The sale of Genesee 3 resulted in a gain of $77 million, which was recognized in gains on sale of assets and other on the statement of earnings during the fourth quarter of 2019.

On the closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Sunhills mine to the Keephills 3 facility. The Sunhills mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. On Oct. 1, 2019, upon termination of this agreement, the Sunhills mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings in the fourth quarter of 2019.

E. Termination of 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 Mar. 31, 2018. This announcement was expected and the Corporation took steps to re-take dispatch control for the units effective Mar. 31, 2018.

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on Mar. 29, 2018. The Corporation disputed the termination payment received. The Balancing Pool excluded certain mining and corporate assets that should have been included in the net book value calculation, which the Corporation pursued from the Balancing Pool through an arbitration initiated under the PPAs. On Aug. 26, 2019, the Corporation announced it was successful in the arbitration and received the full amount it was seeking to recover of $56 million, plus GST and interest.

F. Strategic Investment by Brookfield

On Mar. 25, 2019, the Corporation announced that it had entered into an agreement (the "Investment Agreement") whereby Brookfield Renewable Partners or its affiliates (collectively "Brookfield") agreed to invest $750 million (the "Investment") in the Corporation. Under the terms of the Investment Agreement, Brookfield agreed to invest $750 million in the Corporation through the purchase of exchangeable securities, which are exchangeable by Brookfield into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA").

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions being met.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures. See Note 24 for further details.

In addition, subject to the exceptions in the Investment Agreement, Brookfield has committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent at the conclusion of the prescribed share purchase period, provided that Brookfield is not obligated to purchase any common shares at a price per share in excess of $10 per share.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to provide advice and recommendations in connection with the operation, and maximizing the value, of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the operations, maintenance and administration expense on the statements of earnings (loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment (which occurred on May 1, 2019).

On April 23, 2019, The Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield transaction. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sep. 14, 2020. Refer to Note 35 for further details.

G. Skookumchuck Wind Project

On April 12, 2019, TransAlta signed an agreement with Southern Power to purchase a 49 per cent interest in the Skookumchuck wind project, a 136.8 MW wind project currently under construction and located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy. TransAlta has the option to make its investment when the facility reaches its commercial operation date, which is expected to be in the first half of 2020. TransAlta's 49 per cent interest in the total capital investment is expected to be $150 million to $160 million, a portion of which is expected to be funded with tax equity financing .

H. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). During the second quarter of 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019. Tidewater Midstream and Infrastructure Ltd ("Tidewater") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. During the fourth quarter of 2019, TransAlta recognized a right-of-use asset and lease liability for the portion of the Pioneer Pipeline that is not directly owned.

During the year ended Dec. 31, 2019, TransAlta invested $83 million in the Pioneer Pipeline and has invested $100 million life-to-date. The Pioneer Pipeline is held in a separate entity that is a joint operation with Tidewater. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation. The Pioneer Pipeline is classified as a joint operation, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations. If these facts and circumstances change, the classification of the joint arrangement may change.

I. Mothballing of Sundance Units

On Mar. 8, 2019, the Corporation announced that the Alberta Electric System Operator ("AESO") granted an extension to the mothballing of Sundance Units 3 and 5, which will remain mothballed until Nov. 1, 2021, extended from April 1, 2020. The extensions were requested by TransAlta based on its assessment of market prices and market conditions. TransAlta has the ability to return either of the units back to full operation by providing three months' notice to the AESO.

J. US Wind Projects

On Feb. 20, 2018, TransAlta Renewables Inc. ("TransAlta Renewables") announced it entered into an arrangement to acquire interests in two construction-ready wind projects in the Northeastern United States (collectively, the "US Wind Projects"). The Big Level wind project ("Big Level") consists of a 90 MW wind project located in Pennsylvania that has a 15-year PPA with Microsoft Corp., and the Antrim wind project ("Antrim") consists of a 29 MW wind project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. The Counterparties in the PPAs all have a Standard & Poor's credit ratings of A+ or better.

A subsidiary of TransAlta acquired Big Level on Mar. 1, 2018 and Antrim on Mar. 28, 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in Big Level from a subsidiary of TransAlta Power Ltd. ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns Big Level directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of Big Level. 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.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, the Corporation recognized $50 million for assets under construction in PP&E and $15 million in intangibles. The TransAlta subsidiary also paid the final holdback for the Big Level development project of $7 million (US$5 million) on the closing of Antrim.

Cost estimates for the US Wind Projects were reforecasted to be within the range of US$250 million to US$270 million, primarily due to construction and weather-related impacts as well as higher interconnection costs. TransAlta Renewables funded these costs either by acquiring additional tracking preferred shares issued by TA Power or by subscribing for interest-bearing promissory notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes were used exclusively in connection with the acquisition and construction of the US Wind Projects.

During 2019, TransAlta Renewables funded the acquisition of Antrim and the construction costs of the US Wind Projects by subscribing for $142 million (US$105 million) of interest-bearing promissory notes and $78 million (US $59 million) of tracking preferred shares.

Big Level and Antrim each began commercial operations in December 2019. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US $85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the Consolidated Statements of Financial Position.

From the tax equity proceeds, a subsidiary of TransAlta repaid $52 million (US$40 million) of the interest-bearing promissory notes from TransAlta Renewables. The remaining amount of the tax equity proceeds is held as reserves within the project entity and will be released upon certain conditions being met. Once these conditions are met, the reserves will be released and the subsidiary of TransAlta will repay the remaining outstanding interest-bearing promissory notes from TransAlta Renewables.

K. Normal Course Issuer Bid

2019

On May 27, 2019, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may purchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019. 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 May 29, 2019, and ends on May 28, 2020, 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 176,447 common shares (being 25 per cent of the average daily trading volume on the TSX of 705,788 common shares for the six months ended April 30, 2019) 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, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million. See Note 26 for further details.

2018

On March 9, 2018, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to such NCIB, the Corporation was permitted to 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.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled a total of 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million.

L. Windrise

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was selected by the AESO as one of the three successful projects in the third round of the Renewable Electricity Program. The Windrise wind project, 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 to $285 million and is targeted to reach commercial operation during the first half of 2021.

M. Kent Hills 3 Wind Project

During 2017, a subsidiary of TransAlta Renewables, Kent Hills Wind LP ("KHWLP"), entered into a long-term contract with New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 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 is fully operational, bringing total generating capacity of the Kent Hills wind farm to 167 MW.

N. 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 MWs 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.

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

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, 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 PP&E and $1 million against intangibles. See Note 7 for further details.

O. 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 "Offering"). 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 of the Offering 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 was used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(J) 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. See Note 12 for further details of TransAlta's ownership of TransAlta Renewables.

P. $345 Million Financing Related to the Off-Coal Agreement

On July 20, 2018, the Corporation monetized the payments under the Off-Coal Agreement with the Government of Alberta by closing a $345 million bond offering through its indirect wholly owned subsidiary, TransAlta OCP LP ("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.

Q. 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. See Note 23 for further details.

R. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its then 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. See Note 23 for further details.

S. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited

On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidiary of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the facility has not reached commercial operation within a specified time period. FMG is asserting that the South Hedland facility did not achieve commercial operation in accordance with the terms of the South Hedland PPA within the specified time period.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation is taking all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized. The South Hedland facility has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA. This matter is scheduled to proceed to trial beginning June 15, 2020. See also Note 35.

T. Reacquisition of Solomon Facility

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon facility from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon facility on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action in the Supreme Court of Western Australia to recover all, or a significant portion of, this amount from FMG. A trial date for this matter has not yet been scheduled. See also Note 35.

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

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

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

V. Force Majeure Relief – Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool sought to set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. The Court of Queen's Bench dismissed this application. ENMAX and the Balancing Pool are now attempting to appeal that decision in the Court of Appeal, which requires leave (permission) of the Court. The leave application was heard on Nov. 13, 2019. On Feb. 13, 2019, the Alberta Court of Appeal granted the Balancing Pool and ENMAX permission to appeal. The next step is for TransAlta to continue to defend the arbitration award in the appeal application, which will likely be heard in 2020.

W. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was effective on Jan. 1, 2017, and, in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate, effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. In December 2018, TransAlta exercised its option to terminate its land lease agreement, where the Mississauga facility is located, with Boeing Canada Inc. effective Dec. 31, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

The NUG Contract provided the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations. Further details on the NUG Contract and its impact on these financial statements can be found in Note 9(B).

X. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for net proceeds to the Corporation of $61 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Corporation's revenues are derived from the sale of physical power, capacity and environmental attributes, leasing of power facilities, and from energy marketing and trading activities, which the Corporation disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	395	10	205	87	244	142	—	—	1,083
Revenue from leases(1)	65	—	—	65	—	—	—	—	130
Revenue from derivatives	(17)	160	2	—	18	—	129	4	296
Government incentives	—	—	—	—	8	—	—	—	8
Revenue from other(2)	373	401	2	8	42	14	—	(10)	830
Total revenue	**816**	**571**	**209**	**160**	**312**	**156**	**129**	**(6)**	**2,347**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	41	10	—	—	27	—	—	—	78
Over time	354	—	205	87	217	142	—	—	1,005
Total revenue from contracts with customers	**395**	**10**	**205**	**87**	**244**	**142**	**—**	**—**	**1,083**

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(2) Includes merchant revenue and other miscellaneous.

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	517	9	224	91	206	132	—	—	1,179
Revenue from leases(1)	68	—	—	68	27	7	—	—	170
Revenue from derivatives	(1)	115	4	—	(20)	—	67	—	165
Government incentives	—	—	—	—	16	—	—	—	16
Revenue from other(2)	328	318	4	6	53	17	—	(7)	719
Total revenue	912	442	232	165	282	156	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	38	9	—	—	18	—	—	—	65
Over time	479	—	224	91	188	132	—	—	1,114
Total revenue from contracts with customers	517	9	224	91	206	132	—	—	1,179

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases (2017 - $247 million).
(2) Includes merchant revenue and other miscellaneous.

B. Contract Liabilities

The Corporation has recognized the following revenue-related contract liabilities:

Contract liabilities	2019	2018
Balance, beginning of the year	**88**	62
IFRS 16 and 15 transition adjustments[1]	**15**	17
Amounts transferred to revenue included in opening balance	**(10)**	(10)
Consideration received	**5**	13
Increases due to interest accrued and expensed during the period	**5**	6
Contract termination associated with the purchase of Keephills 3 (Note 4(D))	**(88)**	—
Balance, end of year	**15**	88
Current portion	**1**	8
Long-term portion	**14**	80

(1) In 2019, on transition to IFRS 16 some contracts that were previously considered leases under IAS 17 did not meet the definition of a lease under IFRS 16 and therefore were assessed under IFRS 15 and balances were transferred from deferred revenue to contract liabilities. In 2018, this adjustment related to the significant financing component added on adoption of IFRS 15.

Contract liabilities in 2018 were primarily comprised of consideration received from the Corporation's Keephills 3 joint operation partner, Capital Power, for which the Corporation had a future obligation to transfer goods and services to Capital Power under the contract. On closing of the Keephills 3 and Genesee 3 swap, wherein the Corporation acquired Capital Power's 50 per cent ownership interest in Keephills 3 and sold its 50 per cent ownership interest in Genesee 3, the agreement with Capital Power was terminated and the Corporation no longer had any further performance obligations and the related contract liability balance was recognized in net earnings.

The remaining contract liabilities outstanding at Dec. 31, 2019, primarily relate to prepayments relating to the Corporation's New Richmond and Bone Creek facilities where the Corporation still has to fulfil its performance obligations.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

Additionally, in many of the Corporation's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Corporation's influence. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved. Further, adjustments to revenue to recognize a significant financing component in a contract are not included in the amounts disclosed for remaining performance obligations.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Corporation from its contractual portfolio.

Canadian Coal

At Dec. 31, 2019, the Corporation has PPAs with the Balancing Pool for capacity and electricity from two of its coal plants, as dispatched, with contract end dates of Dec. 31, 2020. All generation produced is delivered for the benefit of the customer. Certain sources of revenue under one PPA contract are accounted for as a lease and are excluded from these disclosures. Pricing is comprised of multiple components, of both fixed and variable nature, consisting of a capacity payment based on a return of capital, availability payments (from or to the customer) based on the 30-day rolling average pool price and actual availability of the plant as compared to targeted availability specified in the PPAs, recovery of regulatory pass-through costs, and payments for delivery of energy based on the variable cost of producing the energy. Energy-related payments are variable depending on output from the plant, which is dependent upon market demand and the operational ability of the plant. Revenues are generally recognized over time, on a monthly basis. Future revenues that are based upon variable consideration are considered to be fully constrained and are excluded from these disclosures.

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal plants. The contracts range in duration from one to three years. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

The Corporation has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer, under which the Corporation will receive a fixed capacity payment and variable energy payments based on production.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $452 million, of which the Corporation expects to recognize approximately $116 million over the next fiscal year and on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

US Coal

The Corporation's long-term contract for the sale of electricity produced at its US Coal plant is considered a derivative and is designated as an all-in-one hedge. Accordingly, while revenues for electricity delivered to the customer are recognized pursuant to the contractual terms, the revenues are not accounted for under IFRS 15 and the contract has been excluded from any required IFRS 15 disclosures.

The Corporation also has a contract for the sale of byproducts of coal combustion from its US Coal plant. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

Canadian Gas

At Dec. 31, 2019, the Corporation has contracts with customers to deliver energy services from one of its gas plants in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. A summary of the key terms of these contracts is set out below.

The energy supply agreements require specified amounts of steam to be delivered to each customer, and have pricing terms that include fixed and variable charges for electricity, capacity and steam, as well as a true-up based on contractual minimum volumes of steam. The steam reconciliation is based on an estimate of the customer's steam volume taken and the contractual minimum volume, and various factors including the annual average market price of electricity and the average locally posted and index prices of natural gas, as well as transportation. For steam volumes not taken by the customer, a revenue-sharing mechanism provides for sharing of revenues earned by the Corporation using that steam to generate and sell electricity. Capacity and electricity pricing vary from contract to contract and are subject to annual indexation at varying rates. Electricity and steam delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

At the same gas plant, the Corporation has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Corporation's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2019, the Corporation had contracts with customers to deliver steam, hot water and chilled water from one of its other gas plants in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $18 million in total, of which the Corporation expects to recognize between approximately $4 million to $6 million annually for the duration of the contracts.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to some of the Corporation's other gas facilities' contracts in Ontario; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas

At Dec. 31, 2019, the Corporation has PPAs with customers to deliver electricity from its gas plants located in Australia. One contract is considered to be a lease and is excluded from these disclosures. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2021 to 2042.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $2,095 million, of which the Corporation expects to recognize approximately $223 million in total over the next three fiscal years and on average, between approximately $80 million to $110 million annually thereafter for the duration of the contracts.

Wind and Solar

At Dec. 31, 2019, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind farms located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Corporation expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchaser over the remaining terms of the contracts, from 2020 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $8 million, of which the Corporation expects to recognize between approximately $1 million to $2 million annually through to contract expiry.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to wind energy contracts in Ontario, New Brunswick, Quebec and Wyoming, and for all solar contracts; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Hydro

At Dec. 31, 2019, the Corporation has a PPA with the Balancing Pool to provide the capacity of 12 hydro plants throughout the province of Alberta. The capacity payment is fixed on an annual basis. As part of the PPA, the Corporation also has a financial obligation to the Balancing Pool determined on the basis of notional quantities of electricity delivered and the pool price for the period. The Corporation expects to recognize revenue as it makes capacity available to the customer until completion of the contract term at Dec. 31, 2020. The Corporation also has contracts for blackstart services at specific hydro plants, which conclude in 2020, and a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which concludes in 2021.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2019, are approximately $72 million, which the Corporation expects to recognize in the next two fiscal years.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to all hydro energy contracts in Ontario, British Columbia and Washington; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2019**		2018		2017	
	Fuel and purchased power	**Operations, maintenance and administration**	Fuel and purchased power	Operations, maintenance and administration	Fuel and purchased power	Operations, maintenance and administration
Fuel[1]	**669**	**—**	656	—	685	—
Purchased power	**246**	**—**	210	—	162	—
Mine depreciation	**119**	**—**	136	—	73	—
Salaries and benefits[1]	**52**	**228**	98	245	96	248
Other operating expenses	**—**	**247**	—	270	—	269
Total	**1,086**	**475**	1,100	515	1,016	517

(1) $90 million in 2017 was reclassified from fuel to salaries and benefits to be consistent with the 2018 and 2019 classifications.

7. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. 2019

Centralia Plant

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia Plant CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia Plant CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia Plant CGU exceeded the carrying value, resulting in a full recoverability test in 2019. The updated fair value included sustained changes in the power price market and cost of coal due to contract renegotiations. As a result of the recoverability test, an impairment reversal of $151 million was recorded in the US Coal segment.

The valuations are categorized as Level III fair value measurements and subject to measurement uncertainty based on the key assumptions outlined below, and on inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenses and the level of contractedness under the Memorandum of Agreement for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the plant in 2025.

The Corporation utilized the Corporation's long-range forecast and the following key assumptions in 2019 compared with 2016 assumptions, which was the most recent detailed valuation:

	2019	2016
Mid-Columbia annual average power prices	**US$30 to US$42 per MWh**	US$22 to US$46 per MWh
On-highway diesel fuel on coal shipments	**US$2.35 to US$2.40 per gallon**	US$1.69 to US$2.09 per gallon
Discount rates	**5.2 to 6.4 per cent**	5.4 to 5.7 per cent

During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. The Corporation's current best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment results in the immediate recognition of the full $141 million, through asset impairment charges in net earnings.

Refer to Note 3(A)(IV) and 22 for further details on the Centralia mine decommissioning and restoration provision.

Assets Held for Sale
In the fourth quarter of 2019, the Corporation identified several trucks and associated inventory to be sold within the Canadian Coal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

B. 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. 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 (see Note 4(N)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately seven 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 (refer to Note 17 and 19).

C. 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. 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.

D. Project Development Costs

During 2019, the Corporation wrote off $18 million (2018 - $23 million) in project development costs related to projects that are no longer proceeding.

8. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases associated with the Poplar Creek cogeneration facility and in 2018, the Fort Saskatchewan cogeneration facility are as follows:

As at Dec. 31	2019		2018	
	Minimum lease receipts	Present value of minimum lease receipts	Minimum lease receipts	Present value of minimum lease receipts
Within one year	20	20	30	29
Second to fifth years inclusive	80	74	80	74
More than five years	120	97	140	112
	220	191	250	215
Less: unearned finance lease income	29	—	35	—
Total finance lease receivables	191	191	215	215

	2019	2018
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 13)	15	24
Long-term portion of finance lease receivables	176	191
	191	215

9. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2019	2018	2017
Alberta Off-Coal Agreement	(40)	(40)	(40)
Mississauga cogeneration facility NUG Contract	(1)	—	(9)
Insurance recoveries	(10)	(7)	—
Other expenses	2	—	—
Net other operating income	(49)	(47)	(49)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The swap of ownership interests in Keephills 3 and Genesee 3 will not impact the payments received. Refer to Note 4(D) for further details.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030. In July 2018, the Corporation obtained financing against the OCA payments. Refer to Note 4(P) and 23 for further details.

B. Mississauga Cogeneration Facility Contract

On Dec. 22, 2016, the Corporation announced it had signed the NUG Contract with the IESO for its Mississauga cogeneration facility. The contract was effective on Jan. 1, 2017. The Corporation agreed to terminate the prior contract with the IESO early, which would have otherwise terminated in December 2018.

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

In December 2018, TransAlta exercised its option to terminate its land lease agreement for the site with Boeing Canada Inc. effective Jan. 1, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

C. Insurance Recoveries

During 2019, the Corporation received $10 million in insurance recoveries, which related to insurance proceeds for tower fires at Wyoming Wind and Summerview.

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related to insurance proceeds for the tower fire at Wyoming Wind and a $1 million claim related to equipment repairs within Canadian Coal. There were no insurance recoveries in 2017.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2019	2018	2017
Interest on debt	**161**	184	218
Interest on exchangeable securities (Note 24)	**20**	—	—
Interest income	**(13)**	(11)	(7)
Capitalized interest (Note 17)	**(6)**	(2)	(9)
Loss on redemption of bonds (Note 23)	**—**	24	6
Interest on finance lease obligations	**4**	3	3
Credit facility fees, bank charges and other interest	**15**	13	18
Tax shield on tax equity financing (Note 23)[1]	**(35)**	—	—
Other[2]	**10**	15	(3)
Accretion of provisions (Note 22)	**23**	24	21
Net interest expense	**179**	250	247

(1) Relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim wind projects that was assigned to the tax equity investor. The tax equity investment is treated as debt under IFRS and the monetization of the tax depreciation is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.
(2) In 2019, other interest expense included approximately $5 million (2018 - $7 million, 2017 - nil) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable.

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2019	2018	2017
Earnings before income taxes	**193**	(96)	(54)
Net earnings attributable to non-controlling interests not subject to tax	**(26)**	(19)	(35)
Adjusted earnings before income taxes	**167**	(115)	(89)
Statutory Canadian federal and provincial income tax rate (%)	**26.5%**	26.8%	26.8%
Expected income tax expense (recovery)	**44**	(31)	(24)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**5**	(3)	(11)
Writedown (reversal of writedown) of deferred income tax assets	**(9)**	27	(15)
Statutory and other rate differences	**(31)**	—	110
Other	**8**	1	4
Income tax expense (recovery)	**17**	(6)	64
Effective tax rate (%)	**10%**	5%	72%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2019	2018	2017
Current income tax expense[1]	**35**	28	79
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**22**	(61)	(110)
Deferred income tax expense resulting from changes in tax rates or laws[2,3]	**(31)**	—	110
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[4]	**(9)**	27	(15)
Income tax expense (recovery)	**17**	(6)	64

Year ended Dec. 31	2019	2018	2017
Current income tax expense	**35**	28	79
Deferred income tax recovery	**(18)**	(34)	(15)
Income tax expense (recovery)	**17**	(6)	64

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon facility Nov. 1, 2017.

(2) In 2019, the Corporation recognized a deferred income tax recovery of $31 million related to a decrease in the Alberta corporate tax rate from 12 per cent to 8 per cent. The tax decrease is phased in as follows: 11 per cent effective July 1, 2019, 10 per cent effective January 1, 2020, 9 per cent effective January 1, 2021, and 8 per cent effective January 1, 2022.

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

(4) During the year ended Dec. 31, 2019, the Corporation recorded a reversal of a previous writedown of deferred income tax assets of $9 million (2018 - $27 million writedown, 2017 - $15 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period-end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. The Corporation previously wrote these assets off when it was not considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses. Recognized ordinary income and other comprehensive income has given rise to taxable temporary differences, which forms the primary basis for utilization of some of the tax losses and the reversal of the writedown.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	2019	2018	2017
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**6**	(12)	(108)
Net impact related to net investment hedges	**—**	—	(7)
Net actuarial gains (losses)	**(7)**	5	(4)
Income tax expense reported in equity	**(1)**	(7)	(119)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2019	2018
Net operating loss carryforwards	**494**	547
Future decommissioning and restoration costs	**122**	113
Property, plant and equipment	**(828)**	(896)
Risk management assets and liabilities, net	**(141)**	(145)
Employee future benefits and compensation plans	**56**	68
Interest deductible in future periods	**42**	48
Foreign exchange differences on US-denominated debt	**40**	35
Deferred coal revenues	**—**	23
Other deductible temporary differences	**4**	—
Net deferred income tax liability, before writedown of deferred income tax assets	**(211)**	(207)
Writedown of deferred income tax assets	**(243)**	(266)
Net deferred income tax liability, after writedown of deferred income tax assets	**(454)**	(473)

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

As at Dec. 31	2019	2018
Deferred income tax assets(1)	**18**	28
Deferred income tax liabilities	**(472)**	(501)
Net deferred income tax liability	**(454)**	(473)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2019, the Corporation had recognized a net liability of $1 million (2018 - nil) related to uncertain tax positions.

12. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2019
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.6% - Public shareholders
Kent Hills Wind LP[(1)]	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a coal facility. TransAlta Renewables owns and operates a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Corporation.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind farm located in New Brunswick.

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

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders may elect to automatically reinvest monthly dividends into additional common shares of the Corporation.

As a result of the conversion of the Class B shares, the DRIP and the Offering described in Note 4(O), the Corporation's share of ownership and equity participation in TransAlta Renewables has changed as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9
Jan. 1, 2019 to Mar. 31, 2019	60.8	60.8
Apr. 1, 2019 to June 30, 2019	60.6	60.6
July 1, 2019 to Sept. 30, 2019	60.5	60.5
Oct. 1, 2019 to Dec. 31, 2019	60.4	60.4

Year ended Dec. 31	2019	2018	2017
Revenues	**446**	462	459
Net earnings	**183**	241	13
Total comprehensive income	**138**	281	(24)
Amounts attributable to the non-controlling interests:			
Net earnings	**73**	94	11
Total comprehensive income	**56**	110	—
Distributions paid to non-controlling interests	**69**	79	85

As at Dec. 31	2019	2018
Current assets	**293**	250
Long-term assets	**3,409**	3,497
Current liabilities	**(152)**	(159)
Long-term liabilities	**(1,237)**	(1,192)
Total equity	**(2,313)**	(2,396)
Equity attributable to non-controlling interests	**(941)**	(961)
Non-controlling interests' share (per cent)	**39.6**	39.1

B. TA Cogen

Year ended Dec. 31	2019	2018	2017
Results of operations			
Revenues	**181**	185	175
Net earnings	**43**	29	61
Total comprehensive income	**43**	29	61
Amounts attributable to the non-controlling interest:			
Net earnings	**21**	14	31
Total comprehensive income	**21**	14	31
Distributions paid to Canadian Power Holdings Inc.	**37**	86	87

As at Dec. 31	2019	2018
Current assets	**41**	82
Long-term assets	**328**	354
Current liabilities	**(27)**	(54)
Long-term liabilities	**(19)**	(28)
Total equity	**(323)**	(354)
Equity attributable to Canadian Power Holdings Inc.	**(160)**	(176)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables

As at Dec. 31	2019	2018
Trade accounts receivable	**399**	597
Promissory note receivable[(1)]	**—**	25
Collateral paid (Note 15)	**42**	105
Current portion of finance lease receivables (Note 8)	**15**	24
Income taxes receivables	**6**	5
Trade and other receivables	**462**	756

(1) The promissory note receivable relates to funding provided for the Antrim wind project in 2018. Refer to Note 4(J) for further details.

14. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2019

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	—	—	411	411
Restricted cash	—	—	32	32
Trade and other receivables	—	—	462	462
Long-term portion of finance lease receivable	—	—	176	176
Risk management assets				
Current	71	95	—	166
Long-term	607	33	—	640
Other assets (Note 21)	—	—	47	47
Financial liabilities				
Accounts payable and accrued liabilities	—	—	413	413
Dividends payable	—	—	37	37
Risk management liabilities				
Current	1	80	—	81
Long-term	1	28	—	29
Credit facilities, long-term debt and finance lease obligations[2]	—	—	3,212	3,212
Exchangeable securities	—	—	326	326

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

Carrying value as at Dec. 31, 2018

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Total
Financial assets					
Cash and cash equivalents[1]	—	—	89	—	89
Restricted cash	—	—	66	—	66
Trade and other receivables	—	—	731	25	756
Long-term portion of finance lease receivables	—	—	191	—	191
Risk management assets					
Current	60	86	—	—	146
Long-term	629	33	—	—	662
Other assets	—	—	37	15	52
Financial liabilities					
Accounts payable and accrued liabilities	—	—	496	—	496
Dividends payable	—	—	58	—	58
Risk management liabilities					
Current	1	89	—	—	90
Long-term	1	40	—	—	41
Credit facilities, long-term debt and finance lease obligations[2]	—	—	3,267	—	3,267

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

B. Fair Value of Financial Instruments

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

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

I. Level I, II and III Fair Value Measurements

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

a. Level I

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

b. Level II

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

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Corporation’s commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

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

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be 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 price relationships.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

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

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

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes and shapes.

As at Dec. 31	**2019**		2018	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale – US	**737**	+46 -139	801	+116 -116
Unit contingent power purchases	**(6)**	+1 -1	18	+4 -4
Structured products – Eastern US	**7**	+2 -2	6	+5 -5
Full requirements – Eastern US	**10**	+3 -3	—	—
Long-term wind energy sale – Eastern US	**(28)**	+20 -20	(39)	+21 -21
Others	**—**	+7 -7	9	+3 -3

i. Long-Term Power Sale – US

The Corporation has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2021, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$20 to US$28 (Dec. 31, 2018 - US$20 to US$35). The sensitivity analysis has been prepared using the Corporation's assessment that a US$3 to US$9 (Dec. 31, 2018 - US$6) price decrease or increase in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2018 to Dec. 31, 2019, the base fair value and the sensitivity values have decreased by approximately $11 million and $2 million, respectively.

ii. Unit Contingent Power Purchases

Under the unit contingent PPAs, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro-rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as FVTPL.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2019, are nil (Dec. 31, 2018 – nil) and 2.2 per cent to 2.8 per cent (Dec. 31, 2018 – 2.2 per cent to 16.9 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.0 per cent to 2.0 per cent (Dec. 31, 2018 – 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 10.5 per cent (Dec. 31, 2018 – 8.6 per cent and 27.3 per cent), which approximate one standard deviation for each input.

iii. Structured Products – Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate. As at Dec. 31, 2019, the Corporation did not have any open positions on heat rate contracts.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2019, are 91 per cent to 112 per cent and 63 per cent to 116 per cent (Dec. 31, 2018 – 75 per cent to 109 per cent and 63 per cent to 104 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 4.0 per cent to 6.0 per cent (Dec. 31, 2018 – 4.2 per cent to 6.9 per cent) and a change in non-standard shape factors of approximately 4.0 per cent to 10.0 per cent (Dec. 31, 2018 – 4.0 per cent to 9.3 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. As there are no open positions on Level III heat rate option contracts, the implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2019, are nil and nil (Dec. 31, 2018 – 25 per cent to 84 per cent and 70 per cent), respectively. The sensitivity analysis was prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately nil and nil, respectively (2018 – 37 per cent to 49 per cent and 30 per cent, respectively).

iv. Full Requirements – Eastern US

The Corporation has a portfolio of full requirement service contracts, whereby the Corporation agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits and Independent System Operator costs.

The key unobservable inputs used in the portfolio valuation include delivered volume and supply cost. Hourly shaping of consumption will result in a realized cost that may be at a premium (or discount) relative to the average settled price. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement. The sensitivity analysis has been prepared using the Corporation's assessment that a reasonably possible change in the expected portfolio delivery volumes and portfolio's realized cost of supply of (+/-) 5 per cent and (+/-) US$1 per MWh, respectively.

v. Long-Term Wind Energy Sale – Eastern US

In relation to the acquisition of Big Level (See Note 4(J)), the Corporation has a long-term contract for differences whereby the Corporation receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits ("RECs") based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2024 and 2022, respectively. Forward power and REC prices per MWh used in determining the Level III base fair value at Dec. 31, 2019, are US$38 to US$60 and US$9 (Dec. 31, 2018 – US$42 to US $68 and US$7 to US$8), respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent (2018 – 10 per cent), a change in energy prices of US $6 (2018 – US$6) and a change in REC prices of US$1 (2018 – US$1) as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

Commodity risk management assets and liabilities include risk management assets and liabilities that are used in the energy marketing and generation businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2019, are as follows: Level I - $3 million net liability (Dec. 31, 2018 – $3 million net asset), Level II – $9 million net asset (Dec. 31, 2018 – $19 million net liability) and Level III – $686 million net asset (Dec. 31, 2018 – $695 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2019, are primarily attributable to the settlement of contracts and unfavourable foreign exchange rates, partially offset by favourable market prices.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2019 and 2018, respectively:

	Year ended Dec. 31, 2019			Year ended Dec. 31, 2018		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**689**	**6**	**695**	719	52	771
Changes attributable to:						
Market price changes on existing contracts	**77**	**8**	**85**	(7)	(9)	(16)
Market price changes on new contracts	**—**	**14**	**14**	—	4	4
Contracts settled	**(57)**	**(19)**	**(76)**	(90)	(42)	(132)
Change in foreign exchange rates	**(31)**	**(1)**	**(32)**	67	5	72
Transfers into (out of) Level III	**—**	**—**	**—**	—	(4)	(4)
Net risk management assets at end of period	**678**	**8**	**686**	689	6	695
Additional Level III information:						
Gains recognized in other comprehensive income	**46**	**—**	**46**	60	—	60
Total gains included in earnings before income taxes	**57**	**21**	**78**	90	—	90
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**2**	**2**	—	(42)	(42)

III. Other Risk Management Assets and Liabilities

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

Other risk management assets and liabilities with a total net asset fair value of $4 million as at Dec. 31, 2019 (Dec. 31, 2018 – $2 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2019, are primarily attributable to favourable market prices on existing contracts.

IV. Other Financial Assets and Liabilities
The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value[1]				Total carrying
	Level I	Level II	Level III	Total	value[1]
Exchangeable securities - Dec. 31, 2019	**—**	**342**	**—**	**342**	**326**
Long-term debt - Dec. 31, 2019	**—**	**3,157**	**—**	**3,157**	**3,070**
Long-term debt - Dec. 31, 2018	—	3,181	—	3,181	3,204

(1) Includes current portion.

The fair values of the Corporation's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 21) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the Corporation are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	2019	2018	2017
Unamortized net gain at beginning of year	**49**	105	148
New inception gains (losses)	**3**	(14)	12
Change in foreign exchange rates	**—**	5	(7)
Amortization recorded in net earnings during the year	**(43)**	(47)	(48)
Unamortized net gain at end of year	**9**	49	105

15. Risk Management Activities

A. Risk Management Strategy

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: i) financial exposure management and ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges, and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	70	15	85
Long-term	606	1	607
Net commodity risk management assets	676	16	692
Other			
Current	—	—	—
Long-term	—	4	4
Net other risk management assets	—	4	4
Total net risk management assets	676	20	696

As at Dec. 31, 2018	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	59	–	59
Long-term	628	(8)	620
Net commodity risk management assets (liabilities)	687	(8)	679
Other			
Current	–	(3)	(3)
Long-term	–	1	1
Net other risk management liabilities	–	(2)	(2)
Total net risk management assets (liabilities)	687	(10)	677

I. Netting Arrangements
Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	2019				2018			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**316**	**631**	**(191)**	**(100)**	224	657	(116)	(42)
Gross amounts set-off	**(140)**	**(42)**	**140**	**42**	(53)	(6)	53	6
Net amounts as included in the Consolidated Statements of Financial Position	**176**	**589**	**(51)**	**(58)**	171	651	(63)	(36)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Corporation uses three tools:

- A framework of risk controls;
- A pre-defined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Corporation has executed commodity price hedges for its Centralia coal plant and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Corporation's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

Market risk exposures are measured using Value at Risk (VaR) supplemented by sensitivity analysis. There has been no change to the Corporation's exposure to market risks or the manner in which these risks are managed or measured.

i. Commodity Price Risk Management – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2019, associated with the Corporation's proprietary trading activities was $1 million (2018 - $2 million, 2017 - $5 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2019, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $25 million (2018 - $18 million, 2017 - $16 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2019, associated with these transactions was $8 million (2018 - $13 million, 2017 - $5 million).

iii. Commodity Price Risk Management – Hedges

The Corporation's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2019**		2018	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**222**	**—**	2,128	—

During 2019, unrealized pre-tax gains of $1 million (2018 - $4 million, 2017 - $2 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management – Non-Hedges

The Corporation's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2019		2018	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	16,097	7,204	58,885	37,023
Natural gas *(GJ)*	38,062	55,023	80,413	110,488
Transmission *(MWh)*	—	1,818	29	11,163
Emissions *(MWh)*	184	138	—	—
Emissions *(tonnes)*	2,436	2,446	3,134	2,948

b. Interest Rate Risk Management

Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact the Corporation's borrowing costs and the capacity payments received under the Alberta coal PPAs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represents 11 per cent of the Corporation's debt as at Dec. 31, 2019 (2018 – 14 per cent).

Interest rate risk is managed with the use of derivatives. No derivatives related to interest rate risk were outstanding as at Dec. 31, 2019, 2018 or 2017.

c. Currency Rate Risk

The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Corporation may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

i. Net Investment Hedges

When designating foreign currency debt as a hedge of the Corporation's net investment in foreign subsidiaries, the Corporation has determined that the hedge is effective as the foreign currency of the net investment is the same as the currency of the hedge, and therefore an economic relationship is present.

The Corporation's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$370 million (2018 - US$400 million).

ii. Cash Flow Hedges

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

As at Dec. 31	2019			2018			
Notional amount sold	Notional amount purchased	Fair value asset	Maturity	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
CAD124	USD95	—	2020-2021	—	—	—	—

iii. Non-Hedges

As part of the sale of the Corporation's economic interest in the Australian Assets to TransAlta Renewables, the Corporation agreed to mitigate the risks to TransAlta Renewables shareholders of adverse changes in the USD and AUD in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program.

The Corporation also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	**2019**			2018			
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures							
AUD286	**CAD266**	**—**	**2020 - 2023**	AUD218	CAD205	(5)	2019-2022
USD108	**CAD139**	**(4)**	**2020 - 2023**	USD164	CAD214	(7)	2019-2022
Foreign exchange forward contracts – foreign-denominated debt							
CAD191	**USD150**	**6**	**2022**	CAD124	USD100	10	2022

iv. Impacts of currency rate risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cent (2018 and 2017 - four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	**2019**		2018		2017	
Currency	**Net earnings increase (decrease)**(1)	**OCI gain**(1),(2)	Net earnings increase(1)	OCI gain(1),(2)	Net earnings decrease(1)	OCI gain(1),(2)
USD	**(18)**	**2**	(13)	—	(5)	—
AUD	**(6)**	**—**	(7)	—	(7)	—
Total	**(24)**	**2**	(20)	—	(12)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

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

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2019:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	85	15	**100**	**462**
Long-term finance lease receivable	100	—	**100**	**176**
Risk management assets[1]	99	1	**100**	**806**
Loan receivable[2]	—	100	**100**	**47**
Total				**1,491**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) The counterparty has no external credit rating. Refer to Note 21 for further details.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on historical rates of default by segment of trade receivables as well as forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2019.

The Corporation's maximum exposure to credit risk at Dec. 31, 2019, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2019, was $5 million (2018 - $13 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. As at Dec. 31, 2019, TransAlta maintains investment grade ratings from one credit rating agency and below investment grade ratings from three credit rating agencies. Between 2020 and 2022, the Corporation has approximately $1,217 million of debt maturing, comprised of approximately $920 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. For the debt maturing in 2020, we expect to utilize our existing cash and credit facilities and we expect to refinance the debt maturing in 2022. Refer to Note 4(F) and 24 for further details.

Collateral is posted based on negotiated terms with counterparties, which can include the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Board; and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Corporation does not use derivatives or hedge accounting to manage liquidity risk.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Accounts payable and accrued liabilities	413	—	—	—	—	—	413
Long-term debt[1]	494	98	625	372	105	1,410	3,104
Exchangeable securities[2]	—	—	—	—	—	350	350
Commodity risk management assets	(89)	(89)	(143)	(139)	(135)	(97)	(692)
Other risk management (assets) liabilities	1	—	(6)	2	—	(1)	(4)
Lease obligations	19	14	9	6	4	90	142
Interest on long-term debt and lease obligations[3]	161	138	128	98	87	671	1,283
Interest on exchangeable securities[2, 3]	25	25	25	24	24	—	123
Dividends payable	37	—	—	—	—	—	37
Total	**1,061**	**186**	**638**	**363**	**85**	**2,423**	**4,756**

(1) Excludes impact of hedge accounting.
(2) Assumes the debentures will be exchanged on Jan. 1, 2025. Refer to Note 24 for further details.
(3) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. Total Return Swaps

The Corporation has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2020	2021	2022	2023	2024	2025 and thereafter
Cash flow hedges						
Foreign Currency Forward Contracts						
Notional amount ($ millions)						
CAD/USD	116	8	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7672	0.7686	—	—	—	—
Commodity Derivative Instruments						
Electricity						
Notional amount (thousands MWh)	3,465	3,424	3,329	3,329	3,338	2,628
Average Price ($ per MWh)	67.82	71.06	73.55	75.39	77.28	79.20

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

As at Dec. 31, 2019

	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	**19 MMWh**	**678**	**Risk management assets**	**47**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD483**	**Credit facilities, long-term debt and finance lease obligations**	**21**

As at Dec. 31, 2018

	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	23 MMWh	687	Risk management assets	60
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD400	CAD546	Credit facilities, long-term debt and finance lease obligations	(41)

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31, 2019	**2019**		2018	
	Change in fair value used for measuring ineffectiveness	**Cash flow hedge reserve**[1]	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve[1]
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**47**	**527**	60	508

	Change in fair value used for measuring ineffectiveness	**Foreign currency translation reserve**[1]	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[1]
Net investment hedges				
Net investment in foreign subsidiaries	**21**	**(21)**	(41)	17

(1) Included in AOCI

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness. There is no ineffectiveness recognized in profit or loss.

The impact of hedged items designated in hedging relationships on OCI and net earnings is:

		Year ended Dec. 31, 2019			
		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	77	Revenue	(59)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	**77**	**OCI impact**	**(53)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $68 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

		Year ended Dec. 31, 2018			
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(9)	Revenue	(67)	Revenue	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	(9)	OCI impact	(57)	Net earnings impact	—

		Year ended Dec. 31, 2017 (as reported under IAS 39)			
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	163	Revenue	(172)	Revenue	—
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Cross-currency swaps	(26)	Foreign exchange (gain) loss	24	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	136	OCI impact	(138)	Net earnings impact	—

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminated the contract effective Jan. 1, 2017. Accordingly, in 2017 the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 9(B) for further details.

II. Effect of Non-Hedges

For the year ended Dec. 31, 2019, the Corporation recognized a net unrealized gain of $33 million (2018 - loss of $29 million, 2017 - gain of $45 million) related to commodity derivatives.

For the year ended Dec. 31, 2019, a gain of $24 million (2018 - gain of $3 million, 2017 - gain of $28 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized gains of $6 million (2018 - gains of $4 million, 2017 - losses of $2 million) and net realized gains of $18 million (2018 - losses of $1 million, 2017 - gains of $30 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2019, the Corporation provided $42 million (2018 – $105 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2019, the Corporation held $3 million (2018 – $17 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

As at Dec. 31, 2019, the Corporation had posted collateral of $112 million (Dec. 31, 2018 – $120 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $51 million (Dec. 31, 2018 – $120 million) of collateral to its counterparties.

16. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

The components of inventory are as follows:

As at Dec. 31	2019	2018
Parts and materials	**108**	113
Coal	**130**	108
Deferred stripping costs	**6**	7
Natural gas	**3**	4
Purchased emission credits	**4**	10
Total	**251**	242

The change in inventory is as follows:

Balance, Dec. 31, 2017	219
Net addition	20
Change in foreign exchange rates	3
Balance, Dec. 31, 2018	242
Net addition	**12**
Change in foreign exchange rates	**(3)**
Balance, Dec. 31, 2019	**251**

No inventory is pledged as security for liabilities.

17. Property, Plant and Equipment

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

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2017	95	5,888	1,982	3,228	1,315	95	370	12,973
Additions[2]	—	—	—	1	—	275	8	284
Additions - finance lease	—	—	—	—	10	—	—	10
Disposals	(3)	—	—	—	(1)	—	(3)	(7)
Impairment charge (Note 7)	—	(38)	—	(11)	—	—	—	(49)
Revisions and additions to decommissioning and restoration costs	—	(12)	(1)	(3)	(16)	—	—	(32)
Retirement of assets	—	(47)	(17)	(6)	(16)	—	(4)	(90)
Change in foreign exchange rates	2	105	(13)	26	7	4	—	131
Transfers	—	41	13	51	39	(174)	12	(18)
As at Dec. 31, 2018	94	5,937	1,964	3,286	1,338	200	383	13,202
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(7)**	**(101)**	**—**	**—**	**(108)**
Additions[4]	**—**	**—**	**—**	**—**	**—**	**407**	**115**	**522**
Acquisitions (Note 4(D) and 4(J))[5]	**—**	**300**	**—**	**—**	**—**	**139**	**—**	**439**
Disposals[6]	**(2)**	**(389)**	**(260)**	**—**	**(34)**	**—**	**(19)**	**(704)**
Impairment (charges) reversals (Note 7)	**—**	**448**	**—**	**(2)**	**(15)**	**—**	**—**	**431**
Revisions and additions to decommissioning and restoration costs	**—**	**(62)**	**11**	**2**	**26**	**—**	**—**	**(23)**
Retirement of assets	**—**	**(158)**	**(26)**	**(7)**	**(10)**	**—**	**—**	**(201)**
Change in foreign exchange rates	**(1)**	**(63)**	**(40)**	**(17)**	**(3)**	**(4)**	**(6)**	**(134)**
Transfers[7]	**—**	**103**	**22**	**319**	**25**	**(514)**	**16**	**(29)**
As at Dec. 31, 2019	**91**	**6,116**	**1,671**	**3,574**	**1,226**	**228**	**489**	**13,395**
Accumulated depreciation								
As at Dec. 31, 2017	—	3,431	1,072	1,037	713	—	142	6,395
Depreciation	—	306	79	123	125	—	16	649
Retirement of assets	—	(56)	(13)	(2)	(12)	—	—	(83)
Disposals	—	—	—	—	(1)	—	(4)	(5)
Change in foreign exchange rates	—	84	(3)	6	5	—	—	92
Transfers	—	—	(7)	(3)	—	—	—	(10)
As at Dec. 31, 2018	—	3,765	1,128	1,161	830	—	154	7,038
Adjustments on implementation of IFRS 16 (Note 3)[3]	**—**	**—**	**—**	**(3)**	**(43)**	**—**	**—**	**(46)**
Depreciation	**—**	**304**	**77**	**136**	**97**	**—**	**16**	**630**
Retirement of assets	**—**	**(158)**	**(23)**	**(3)**	**(6)**	**—**	**—**	**(190)**
Disposals[5]	**—**	**(170)**	**(255)**	**—**	**(14)**	**—**	**—**	**(439)**
Impairment reversal (Note 7)	**—**	**297**	**—**	**—**	**—**	**—**	**—**	**297**
Change in foreign exchange rates	**—**	**(52)**	**(16)**	**(4)**	**(2)**	**—**	**(2)**	**(76)**
Transfers	**—**	**10**	**(11)**	**(3)**	**(22)**	**—**	**—**	**(26)**
As at Dec. 31, 2019	**—**	**3,996**	**900**	**1,284**	**840**	**—**	**168**	**7,188**
Carrying amount								
As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
As at Dec. 31, 2019	**91**	**2,120**	**771**	**2,290**	**386**	**228**	**321**	**6,207**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance, and the Australian gas pipeline.
(2) Includes $7 million related to the acquisition of Big Level.
(3) Includes net $33 million transferred to right of use assets and $29 million of finance lease assets that were derecognized on implementation of IFRS 16. Refer to Note 3 for further details.
(4) Includes cash additions of $417 million (including $169 million related to the construction of the US Wind Projects), $100 million related to the Pioneer Pipeline (including $15 million transferred from other assets) and $5 million related to the Keephills 3 and Genesee 3 asset swap. Refer to Note 4 for further details of these transactions.
(5) Includes $308 million related to the acquisition of the Keephills 3 facility with $300 million included in coal generation and the remainder in assets under construction.
(6) In 2019, we sold the Genesee 3 facility and sold the major components of the Mississauga facility. In addition, Centralia sold boiler parts included in capital spares and other for a net loss of $17 million. The Sunhills mine also sold trucks included in mining property and equipment for a net loss of $18 million. Both were recognized in other gains on the statement of earnings (loss).
(7) Mainly relates to transferring the Pioneer Pipeline and US Wind Projects from assets under construction to coal generation and renewable generation, respectively.

The Corporation capitalized $6 million of interest to PP&E in 2019 (2018 - $2 million) at a weighted average rate of 5.9 per cent (2018 – 4.5 per cent). Finance lease additions in 2018 were for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2019, was nil as these were transferred to right of use assets on implementation of IFRS 16 (2018 - $65 million).

18. Right of Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right of use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Pipeline	Total
New leases recognized Jan. 1, 2019	29	22	1	—	—	52
Adjustments on recognition(1)	(1)	(4)	—	—	—	(5)
Transfers from PP&E, intangibles and other assets	—	—	3	35	—	38
As at Jan. 1, 2019	28	18	4	35	—	85
Additions	32	2	—	2	45	81
Depreciation	(1)	(4)	(2)	(11)	—	(18)
Change in foreign exchange rates	(1)	—	—	—	—	(1)
Transfers	—	—	—	(1)	—	(1)
As at Dec. 31, 2019	58	16	2	25	45	146

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

In November 2019, the Corporation recognized a right of use asset and corresponding lease liability related to the initial 15-year term of its contract for transporting natural gas on the Pioneer Pipeline. The transportation contract provides the Corporation with the right to extend the contract for up to eight additional renewal periods of 24-months each. The amounts recognized represent the 50 per cent of the pipeline that is not owned by the Corporation.

In December 2019, the Corporation recognized an additional $31 million of right of use assets and $31 million of lease liabilities for land leases at certain wind farms as a result of revised interpretations of the unit of account / identified asset concepts present in IFRS 16.

For the year ended Dec. 31, 2019, TransAlta paid $25 million related to recognized lease liabilities, consisting of $4 million in interest and $21 million in principal repayments.

For the year ended Dec. 31, 2019, the Corporation expensed $2 million related to short-term and $1 million related to low value leases. Short term leases (term of less than 12 months) and leases with total lease payments below the Corporation's capitalization threshold do not require recognition as lease liabilities and right of use assets.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2019, the Corporation expensed $6 million in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 10, 15, 23 and 35.

19. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2017	178	314	223	29	744
Additions(1)	—	—	—	53	53
Retirements and disposals(2)	—	(2)	—	—	(2)
Change in foreign exchange rates	—	3	—	—	3
Transfers	7	24	14	(36)	9
As at Dec. 31, 2018	185	339	237	46	807
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(5)**	**—**	**—**	**(5)**
Additions	**—**	**—**	**—**	**14**	**14**
Acquisition	**—**	**1**	**—**	**15**	**16**
Disposals (Note 4(D))	**(37)**	**(1)**	**—**	**—**	**(38)**
Change in foreign exchange rates	**—**	**(4)**	**(1)**	**(1)**	**(6)**
Transfers	**1**	**48**	**14**	**(63)**	**—**
As at Dec. 31, 2019	**149**	**378**	**250**	**11**	**788**
Accumulated amortization					
As at Dec. 31, 2017	125	188	67	—	380
Amortization	9	32	9	—	50
Retirements and disposals	—	(1)	—	—	(1)
Change in foreign exchange rates	—	2	—	—	2
Transfers	(17)	—	20	—	3
As at Dec. 31, 2018	117	221	96	—	434
Assets transferred to right of use assets on implementation of IFRS 16 (Note 3 and 18)	**—**	**(3)**	**—**	**—**	**(3)**
Amortization	**8**	**31**	**11**	**—**	**50**
Disposals (Note 4(D))	**(9)**	**(1)**	**—**	**—**	**(10)**
Change in foreign exchange rates	**—**	**(1)**	**—**	**—**	**(1)**
Transfers	**1**	**(1)**	**—**	**—**	**—**
As at Dec. 31, 2019	**117**	**246**	**107**	**—**	**470**
Carrying amount					
As at Dec. 31, 2017	53	126	156	29	364
As at Dec. 31, 2018	68	118	141	46	373
As at Dec. 31, 2019	**32**	**132**	**143**	**11**	**318**

(1) Includes $33 million related to the acquisition of Big Level.
(2) Includes the impairment charge of $1 million relating to Kent Breeze. See Note 7 for further details.

20. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	2019	2018
Hydro	**258**	259
Wind and Solar	**176**	175
Energy Marketing	**30**	30
Total goodwill	**464**	464

For the purposes of the 2019 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Hydro, Wind and Solar, and Energy Marketing segments 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. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2019 models ranged between $5 to $183 per MWh during the forecast period (2018 – $6 to $179 per MWh). Discount rates used for the goodwill impairment calculation in 2019 ranged from 3.6 per cent to 7.0 per cent (2018 – 5.3 per cent to 6.6 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

21. Other Assets

The components of other assets are as follows:

As at Dec. 31	2019	2018
South Hedland prepaid transmission access and distribution costs	**67**	72
Deferred licence fees	**9**	11
Project development costs	**19**	47
Deferred service costs	**—**	12
Long-term prepaids and other assets	**56**	55
Loan receivable	**47**	37
Total other assets	**198**	234

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

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

Project development costs include the project costs for Windrise (Note 4(L)) and the US wind development projects (Note 4(B)). Some projects were written off in 2019 and 2018 as they are no longer proceeding (see Note 7(D)).

Deferred service costs related to TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. As part of the Genesee Unit 3 and Keephills Unit 3 swap, these assets were included in the transaction (Note 4(D)).

Long-term prepaids and other assets includes: the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 35(F), the Keephills Unit 3 provincially required transmission deposit which is anticipated to be reimbursed over the next two years to 2021, as long as certain performance criteria are met, and other miscellaneous prepaids and deposits.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $47 million (2018 – $37 million) (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022.

22. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2017	437	33	470
Liabilities incurred	5	17	22
Liabilities settled	(31)	(10)	(41)
Accretion	24	—	24
Acquisition of liabilities (Big Level)	—	8	8
Revisions in estimated cash flows	2	3	5
Revisions in discount rates	(37)	—	(37)
Reversals	—	(5)	(5)
Change in foreign exchange rates	7	3	10
Balance, Dec. 31, 2018	407	49	456
IFRS 16 transition adjustment	**—**	**(2)**	**(2)**
Liabilities incurred	**7**	**7**	**14**
Liabilities settled	**(34)**	**(9)**	**(43)**
Accretion	**23**	**—**	**23**
Acquisition of liabilities	**16**	**3**	**19**
Disposition of liabilities	**(23)**	**(9)**	**(32)**
Revisions in estimated cash flows(1)	**96**	**7**	**103**
Revisions in discount rates	**16**	**—**	**16**
Reversals	**—**	**(1)**	**(1)**
Change in foreign exchange rates	**(7)**	**—**	**(7)**
Balance, Dec. 31, 2019	**501**	**45**	**546**

(1) During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. Refer to Note 3(A)(III) for further details. In addition, due to the changes in estimated useful lives, described in Note 3(A)(IV), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed. The use of a lower inflation rate decreased the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2018	407	49	456
Current portion	35	35	70
Non-current portion	372	14	386
Balance, Dec. 31, 2019	**501**	**45**	**546**
Current portion	**36**	**22**	**58**
Non-current portion	**465**	**23**	**488**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.3 billion, which will be incurred between 2020 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2019, the Corporation had provided a surety bond in the amount of US$147 million (2018 – US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2019, the Corporation had provided letters of credit in the amount of $128 million (2018 – $122 million) in support of future decommissioning obligations at the Alberta mine.

B. Other Provisions

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Corporation and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Corporation's ability to settle the provisions in the most favourable manner.

23. Credit Facilities, Long-Term Debt and Finance Lease Obligations

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	2019			2018		
	Carrying value	**Face value**	**Interest**(1)	Carrying value	Face value	Interest(1)
Credit facilities(2)	**220**	**220**	**3.5%**	339	339	3.8%
Debentures	**647**	**651**	**5.8%**	647	651	5.8%
Senior notes(3)	**905**	**914**	**5.4%**	943	955	5.4%
Non-recourse(4)	**1,144**	**1,157**	**4.3%**	1,236	1,250	4.4%
Other(5)	**154**	**162**	**7.1%**	39	39	9.2%
	3,070	**3,104**		3,204	3,234	
Finance lease obligations	**142**			63		
	3,212			3,267		
Less: current portion of long-term debt	**(494)**			(130)		
Less: current portion of finance lease obligations	**(19)**			(18)		
Total current long-term debt and finance lease obligations	**(513)**			(148)		
Total credit facilities, long-term debt and finance lease obligations	**2,699**			3,119		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2019 - US$0.7 billion (Dec. 31, 2018 - US$0.7 billion).
(4) Includes US$1 million at Dec. 31, 2019 (Dec. 31, 2018 - US$1 million).
(5) Includes US$117 at Dec. 31, 2019 (Dec. 31, 2018 - US$21 million) of tax equity financing.

Our credit facilities include the Corporation's $1.3 billion committed syndicated bank credit facility expiring in 2023, TransAlta Renewable's $700 million committed syndicated bank credit facility expiring in 2023 and the Corporation's three bilateral credit facilities totalling $240 million expiring in 2021. The $2.0 billion (Dec. 31, 2018 – $1.8 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, US LIBOR, or US base rate – in accordance with a pricing grid that is standard for such facilities.

During 2019, the Corporation renewed these credit facilities and TransAlta Renewables' facility was increased by $200 million to $700 million.

During 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

The Corporation has a total of $2.2 billion (Dec. 31, 2018 – $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $0.7 billion (Dec. 31, 2018 – $0.5 billion). In total, $1.3 billion (Dec. 31, 2018 – $0.9 billion) is not drawn. At Dec. 31, 2019, the $0.9 billion (Dec. 31, 2018 – $1.1 billion) of credit utilized under these facilities was comprised of actual drawings of $220 million (Dec. 31, 2018 – $339 million) and letters of credit of $690 million (Dec. 31, 2018 – $720 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.3 billion available under the credit facilities, the Corporation also has $411 million of available cash and cash equivalents and $17 million ($10 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030.

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040.

During 2018, the Corporation early redeemed its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross-currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

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

A total of US$370 million (2018 - US$400 million) of the senior notes has been designated as a hedge of the Corporation's net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 6.03 per cent.

During 2018, the Corporation:

- Paid out the US$25 million non-recourse debt related to its Mass Solar projects.
- Monetized the OCA and closed a $345 million bond offering through its indirect wholly owned subsidiary TransAlta OCP by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financings related to Big Level and Antrim of $122 million and Lakeswind of $23 million.

During 2019, coinciding with Antrim and Big Level each achieving commercial operation, TransAlta received tax equity funding of approximately US$41 million and US$85 million, respectively. Refer to Note 4(J) for further details.

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind acquired tax equity which was initially recognized at its fair value. Tax equity financing balances are reduced by the value of tax benefits (production tax credits and tax depreciation) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. In 2019, the Big Level and Antrim wind projects claimed accelerated (bonus) tax depreciation of $35 million in total, which was allocated to the tax equity investor, and had the effect of reducing the tax equity financing balance. The maturity dates of each financing are subject to change and primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Corporation anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim - in December 2029, 10 years from commercial operation of the projects; and Lakeswind - March 31, 2024.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2019, the Corporation was in compliance with all debt covenants.

B. Restrictions related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and TransAlta OCP non-recourse bonds with a carrying value of $1,143 million as at Dec. 31, 2019 (Dec. 31, 2018 - $1,235 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2019. 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 2020. At Dec. 31, 2019, $42 million (Dec. 31, 2018 – $33 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, 2019.

Proceeds received from the Big Level and Antrim tax equity financing in the amount of $91 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying outstanding project development costs.

C. Security

Non-recourse debts totalling $719 million as at Dec. 31, 2019 (Dec. 31, 2018 – $766 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which include property, plant and equipment with total carrying amounts of $967 million at Dec. 31, 2019 (Dec. 31, 2018 – $1,021 million) and intangible assets with total carrying amounts of $63 million (Dec. 31, 2018 – $70 million). At Dec. 31, 2019, a non-recourse bond of approximately $119 million (Dec. 31, 2018 – $127 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds have a carrying value of $305 million (Dec. 31, 2018 – $342 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under 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.

D. Principal Repayments

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Principal repayments(1)	494	98	625	372	105	1,410	3,104
Lease obligations	19	14	9	6	4	90	142

(1) Excludes impact of derivatives.

E. Restricted Cash

At Dec. 31, 2019, the Corporation had $15 million in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in the first half of 2020.

The Corporation also had $17 million (Dec. 31, 2018 – $35 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2020. The Corporation had nil (Dec. 31, 2018 – $31 million) restricted cash related to the Kent Hills project financing.

F. Letters of Credit

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

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2019 was $690 million (2018 – $720 million) with no (2018 – nil) amounts exercised by third parties under these arrangements.

24. Exchangeable Securities

On March 25, 2019, the Corporation announced that it had entered into an Investment Agreement whereby Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future adjusted EBITDA ("Option to Exchange"). On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. The remaining $400 million will be invested in October 2020 in exchange for a new series of redeemable, retractable first preferred shares, subject to the satisfaction of certain conditions.

A. $350 Million Unsecured Subordinated Debentures

As at	Dec. 31, 2019		
	Carrying value	**Face value**	**Interest**
Exchangeable debentures – due May 1, 2039	326	350	7%

If Brookfield chooses not to exercise its Option to Exchange as outlined below, TransAlta has the right after Dec. 31, 2028 to redeem for cash all or any portion of the Exchangeable Securities for the original subscription price, plus any accrued but unpaid interest or dividends payable, provided the minimum proceeds to Brookfield for each redemption (other than the final redemption) is not less than $100 million and provided all Exchangeable Securities must be redeemed within 36 months of the first optional redemption.

B. Option to Exchange

As at	Dec. 31, 2019	
Description	**Base fair value**	**Sensitivity**
Option to exchange – embedded derivative	—	+35 -27

The Investment Agreement allows Brookfield the Option to Exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the Option to Exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the Option to Exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, and provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Hydro Assets, provided the 20-day volume-weighted average price ("VWAP") of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the Investment would exceed a 49 equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

25. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2019	2018
Defined benefit obligation (Note 30)	**268**	227
Long-term incentive accruals (Note 29)	**4**	9
Other	**29**	51
Total	**301**	287

26. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

As at Dec. 31	2019		2018	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**284.6**	**3,059**	287.9	3,094
Purchased and cancelled under the NCIB	**(7.7)**	**(83)**	(3.3)	(35)
Stock options exercised	**0.1**	**2**	—	—
Issued and outstanding, end of year	**277.0**	**2,978**	284.6	3,059

B. NCIB Program

Shares purchased by the Corporation under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in deficit.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31	2019	2018
Total shares purchased(1)	**7,716,300**	3,264,500
Average purchase price per share	**$ 8.80**	$ 7.02
Total cost	**68**	23
Weighted average book value of shares cancelled	**83**	35
Amount recorded in deficit	**15**	12

(1) As at Dec. 31, 2019, includes 189,900 (2018 - 204,000) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019 to reflect current market practice and to reflect changes to the take-over bid regime. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 26, 2019. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Corporation's common shares, except in limited circumstances including by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	2019	2018	2017
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
Basic and diluted weighted average number of common shares outstanding (millions)	**283**	287	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.18**	(0.86)	(0.66)

E. Dividends

On Oct. 9, 2019, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2020. On Jan. 16, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Apr. 1, 2020.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

27. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed rate first preferred shares.

As at Dec. 31	2019		2018	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series G Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Aug. 30, 2019, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2019, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (the "Series G Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series H (the "Series H Shares"), there were 140,730 Series G Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series H Shares. Therefore, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2019. As a result, the Series G Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series G Shares for the five-year period from and including Sept. 30, 2019, to, but excluding, Sept. 30, 2024, will be 4.988 per cent, which is equal to the five-year Government of Canada bond yield of 1.188 per cent, determined as of Aug. 30, 2019, plus 3.80 per cent, in accordance with the terms of the Series G Shares.

II. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

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

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

IV. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion
On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation had 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2019.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on the 90-day Treasury Bill rate plus 2.03 per cent.

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

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2019, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.67725	March 31, 2021	2.03	B
B	Floating	0.93575	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29850	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.32500	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of preferred share dividends declared in 2019, 2018 and 2017:

	Total dividends declared		
Series	**2019**	2018	2017
A	**5**	9	5
B	**1**	1	1
C	**8**	14	9
E	**9**	15	8
G	**7**	11	7
Total for the year	**30**	50	30

28. Accumulated Other Comprehensive Income

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

	2019	2018
Currency translation adjustment		
Opening balance, Jan. 1	**17**	(26)
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(59)**	84
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**21**	(41)
Balance, Dec. 31	**(21)**	17
Cash flow hedges		
Opening balance, Jan. 1	**508**	562
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(1)	**19**	(54)
Balance, Dec. 31	**527**	508
Employee future benefits		
Opening balance, Jan. 1	**(29)**	(44)
Net actuarial gains (losses) on defined benefit plans, net of tax(2)	**(26)**	15
Balance, Dec. 31	**(55)**	(29)
Other		
Opening balance, Jan. 1	**(15)**	(3)
Change in ownership of TransAlta Renewables	**1**	4
Intercompany investments at FVOCI	**17**	(16)
Balance, Dec. 31	**3**	(15)
Accumulated other comprehensive income	**454**	481

(1) Net of income tax of $6 million for the year ended Dec. 31, 2019 (2018 - $12 million).
(2) Net of income tax of $7 million for the year ended Dec. 31, 2019 (2018 - $5 million).

29. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares.

During 2019, as a result of the Corporation's change in its intended settlement policy, the accounting classification of the RSUs and PSUs changed from cash-settled to equity-settled. The RSUs and PSUs have been accounted for as equity-settled grants from the dates of the policy change, with fair values determined as at that date. On average, the fair value of outstanding grants used in accounting for the change was $8.29, measured using the black-scholes option pricing model. As a result of this change, the liability for the cash-settled grants ($25 million) has been derecognized and the equity-settled fair value ($24 million) has been recognized in contributed surplus, with the net difference of $1 million representing the cumulative change in compensation expense. No changes were made to the vesting or performance conditions associated with the awards. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expenses related to this plan are recognized during the period earned, with the corresponding amounts due under the plan recorded in contributed surplus (2018 - liabilities). Prior to this change, the liability was valued at the end of each reporting period using the closing price of the Corporation's common shares on the TSX.

The pre-tax compensation expense related to PSUs and RSUs in 2019 was $19 million (2018 - $8 million, 2017 - $15 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $2 million in 2019 (2018 - nil, 2017 - $1 million).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2019, the Corporation granted executive officers of the Corporation a total of 1.4 million stock options with a weighted average exercise price of $5.65 that vest after a three-year period and expire 7 years after issuance (2018 - 0.7 million stock options at $7.45; 2017 - 0.7 million stock options at $7.25). The expense recognized relating to these grants during 2019 was approximately $1 million (2018 - approximately $1 million, 2017 - approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2019, are outlined below:

	Options outstanding		
Range of exercise prices[1] *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 9.00	**3.3**	4.7	**6.34**
22.00 - 30.00	**0.5**	**0.1**	**23.44**
5.00 - 30.00	**3.8**	**4.2**	**8.41**

(1) Options currently exercisable as at Dec. 31, 2019.

30. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the US covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2019. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2019.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the US. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation posted a letter of credit in March 2019 for the amount of $83 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2018, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2019.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**7**	**2**	**1**	**10**
Administration expenses	**2**	**—**	**—**	**2**
Interest cost on defined benefit obligation	**19**	**3**	**1**	**23**
Interest on plan assets	**(12)**	**(1)**	**—**	**(13)**
Curtailment and amendment gain	**(3)**	**—**	**—**	**(3)**
Defined benefit expense	**13**	**4**	**2**	**19**
Defined contribution expense	**9**	**—**	**—**	**9**
Net expense	**22**	**4**	**2**	**28**

Year ended Dec. 31, 2018	Registered	Supplemental	Other	Total
Current service cost	9	2	1	12
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	18	3	1	22
Interest on plan assets	(13)	—	—	(13)
Defined benefit expense	15	5	2	22
Defined contribution expense	10	—	—	10
Net expense	25	5	2	32

Year ended Dec. 31, 2017	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	20	3	1	24
Interest on plan assets	(15)	—	—	(15)
Defined benefit expense	14	5	2	21
Defined contribution expense	11	—	—	11
Net expense	25	5	2	32

C. Status of Plans

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

As at Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**373**	**13**	**–**	**386**
Present value of defined benefit obligation	**(543)**	**(99)**	**(22)**	**(664)**
Funded status – plan deficit	**(170)**	**(86)**	**(22)**	**(278)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(3)**	**(5)**	**(2)**	**(10)**
Other long-term liabilities	**(167)**	**(81)**	**(20)**	**(268)**
Total amount recognized	**(170)**	**(86)**	**(22)**	**(278)**

As at Dec. 31, 2018	Registered	Supplemental	Other	Total
Fair value of plan assets	368	13	–	381
Present value of defined benefit obligation	(514)	(80)	(25)	(619)
Funded status – plan deficit	(146)	(67)	(25)	(238)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(5)	(5)	(1)	(11)
Other long-term liabilities	(141)	(62)	(24)	(227)
Total amount recognized	(146)	(67)	(25)	(238)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
As at Dec. 31, 2017	416	12	–	428
Interest on plan assets	13	–	–	13
Net return on plan assets	(25)	–	–	(25)
Contributions	5	6	1	12
Benefits paid	(42)	(5)	(1)	(48)
Administration expenses	(1)	–	–	(1)
Effect of translation on US plans	2	–	–	2
As at Dec. 31, 2018	368	13	–	381
Interest on plan assets	**12**	**1**	**–**	**13**
Net return on plan assets	**40**	**–**	**–**	**40**
Contributions	**6**	**4**	**1**	**11**
Benefits paid	**(50)**	**(5)**	**(1)**	**(56)**
Administration expenses	**(2)**	**–**	**–**	**(2)**
Effect of translation on US plans	**(1)**	**–**	**–**	**(1)**
As at Dec. 31, 2019	**373**	**13**	**–**	**386**

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

Year ended Dec. 31, 2019	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**66**	**—**	**66**
US	**—**	**28**	**—**	**28**
International	**—**	**102**	**—**	**102**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**40**	**—**	**40**
AA	**—**	**68**	**—**	**68**
A	**—**	**37**	**—**	**37**
BBB	**1**	**21**	**—**	**22**
Below BBB	**—**	**3**	**—**	**3**
Money market and cash and cash equivalents	**—**	**19**	**—**	**19**
Total	**1**	**384**	**1**	**386**

Year ended Dec. 31, 2018	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	65	—	65
US	—	26	—	26
International	—	101	—	101
Private	—	—	1	1
Bonds				
AAA	—	48	—	48
AA	—	64	—	64
A	—	39	—	39
BBB	1	21	—	22
Below BBB	—	3	—	3
Money market and cash and cash equivalents	(2)	14	—	12
Total	(1)	381	1	381

Plan assets do not include any common shares of the Corporation at Dec. 31, 2019, and Dec. 31, 2018. The Corporation charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2019 (2018 - $0.1 million).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2017	561	87	27	675
Current service cost	9	2	1	12
Interest cost	18	3	1	22
Benefits paid	(42)	(5)	(1)	(48)
Actuarial gain arising from demographic assumptions	—	—	—	—
Actuarial loss arising from financial assumptions	(35)	(7)	(2)	(44)
Actuarial gain (loss) arising from experience adjustments	—	—	(1)	(1)
Effect of translation on US plans	3	—	—	3
Present value of defined benefit obligation as at Dec. 31, 2018	514	80	25	619
Current service cost	**7**	**2**	**1**	**10**
Interest cost	**19**	**3**	**1**	**23**
Benefits paid	**(51)**	**(4)**	**(1)**	**(56)**
Curtailment	**(3)**	**—**	**—**	**(3)**
Actuarial loss arising from demographic assumptions	**—**	**—**	**(2)**	**(2)**
Actuarial (gain) loss arising from financial assumptions	**57**	**9**	**2**	**68**
Actuarial (gain) loss arising from experience adjustments	**2**	**9**	**(4)**	**7**
Effect of translation on US plans	**(2)**	**—**	**—**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2019	**543**	**99**	**22**	**664**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2019, is 15.6 years.

F. Contributions

The expected employer contributions for 2020 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**4**	**5**	**1**	**10**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2019			As at Dec. 31, 2018		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.0**	**3.0**	**3.0**	3.9	3.8	3.9
Rate of compensation increase	**2.8**	**3.0**	**—**	2.5	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**7.0**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.9**	**3.8**	**3.9**	3.3	3.3	3.4
Rate of compensation increase	**2.5**	**3.0**	**—**	2.6	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.4**	—	—	7.6
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health-care premium escalation	**—**	**—**	**—**	—	—	—

(1) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2030 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(3) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(4) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.

H. Sensitivity Analysis

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

	Canadian plans			**US plans**	
Year ended Dec. 31, 2019	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**84**	**15**	**2**	**3**	**1**
1% increase in the salary scale	**14**	**—**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**22**	**3**	**—**	**1**	**—**

31. Joint Arrangements

Joint arrangements at Dec. 31, 2019, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by Heartland Generation Ltd., an affiliate of Energy Capital Partners
Pioneer Pipeline	Coal	50	Natural gas pipeline in Alberta operated by Tidewater
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

32. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2019**	2018	2017
(Use) source:			
Accounts receivable	**261**	58	(228)
Prepaid expenses	**—**	19	(75)
Income taxes receivable	**(6)**	—	8
Inventory	**(13)**	(21)	(7)
Accounts payable, accrued liabilities and provisions	**(130)**	(97)	186
Income taxes payable	**9**	(3)	2
Change in non-cash operating working capital	**121**	(44)	(114)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2018	Net cash flows	New leases	Tax shield on tax equity financing	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2019
Long-term debt and lease obligations	3,267	**(70)**	**133**	**(35)**	**—**	**(42)**	**(41)**	**3,212**
Exchangeable securities	—	**350**	**—**	**—**	**—**	**—**	(24)	**326**
Dividends payable (common and preferred)	58	**(85)**	**—**	**—**	**64**	**—**	**—**	**37**
Total liabilities from financing activities	3,325	**195**	**133**	**(35)**	**64**	**(42)**	**(65)**	**3,575**

	Balance Dec. 31, 2017	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2018
Long-term debt and finance lease obligations	3,707	(540)	10	—	95	(5)	3,267
Dividends payable (common and preferred)	34	(86)	—	107	—	3	58
Total liabilities from financing activities	3,741	(626)	10	107	95	(2)	3,325

33. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2019	2018	Increase/ (decrease)
Long-term debt[1]	**3,212**	3,267	**(55)**
Exchangeable securities	**326**	—	**326**
Equity			
Common shares	**2,978**	3,059	**(81)**
Preferred shares	**942**	942	**—**
Contributed surplus	**42**	11	**31**
Deficit	**(1,455)**	(1,496)	**41**
Accumulated other comprehensive income	**454**	481	**(27)**
Non-controlling interests	**1,101**	1,137	**(36)**
Less: available cash and cash equivalents[2]	**(411)**	(89)	**(322)**
Less: principal portion of restricted cash on TransAlta OCP Bonds[3]	**(10)**	(27)	**17**
Less: fair value asset of hedging instruments on long-term debt[4]	**(7)**	(10)	**3**
Total capital	**7,172**	7,275	**(103)**

(1) Includes lease obligations, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.
(2) The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available and used to facilitate repayment of debt.
(3) The Corporation includes the principal portion of restricted cash on TransAlta OCP bonds because this cash is restricted specifically to repay outstanding debt.
(4) The Corporation includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Corporation's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain a strong financial position that enables the Corporation to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also 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. The Corporation has an investment-grade credit rating from DBRS (stable outlook). In 2019, Moody's reaffirmed its issuer rating of Ba1 and revised their rating outlook to stable from positive. During 2019, Fitch Ratings downgraded the Corporation below investment grade to BB+ with a stable outlook; DBRS 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 downgraded the Corporation's Unsecured Debt rating and Issuer Rating to BB + with stable outlook. The Corporation remains focused on strengthening its financial position and cash flow coverage ratios. 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.

Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including 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. These ratios are summarized in the table below:

As at Dec. 31	2019	2018	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.5**	4.8	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**19.0**	20.8	20 to 25
Adjusted net debt to adjusted comparable earnings before interest, taxes, depreciation and amortization (times)	**3.9**	3.6	3.0 to 3.5

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO less the termination payments for the Sundance B and C PPAs plus interest on debt, exchangeable securities and lease obligations (net of capitalized interest) divided by interest on debt, exchangeable securities and lease obligations (net of capitalized interest) plus 50 per cent of dividends paid on preferred shares. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less the termination payments for the Sundance B and C PPAs less 50 per cent of dividends paid on preferred shares divided by adjusted net debt (current and long-term debt plus exchangeable securities plus 50 per cent of outstanding preferred shares less available cash and cash equivalents less principal portion of TransAlta OCP restricted cash and including fair value assets of hedging instruments on debt). The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Adjusted Comparable Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is calculated as adjusted net debt divided by adjusted comparable EBITDA. Adjusted comparable EBITDA is calculated as earnings before interest, taxes, depreciation and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations as well as the termination payments for the Sundance B and C PPAs. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified ranges while the Corporation executes its coal-to-gas transition and growth strategy, but we remain focused on maintaining a strong balance sheet.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, Invest in PP&E and Make Acquisitions

For the years ended Dec. 31, 2019 and 2018, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	**2019**	2018	**Increase (decrease)**
Cash flow from operating activities	**849**	820	**29**
Change in non-cash working capital	**(121)**	44	**(165)**
Cash flow from operations before changes in working capital	**728**	864	**(136)**
Dividends paid on common shares	**(45)**	(46)	**1**
Dividends paid on preferred shares	**(40)**	(40)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(106)**	(165)	**59**
Property, plant and equipment expenditures	**(417)**	(277)	**(140)**
Inflow	**120**	336	**(216)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2019, $1.3 billion (2018 - $0.9 billion) of the Corporation's available credit facilities were not drawn.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

34. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2019, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables	Canada	60.4	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2019	2018	2017
Total compensation	**30**	17	24
Comprised of:			
Short-term employee benefits	**13**	11	14
Post-employment benefits	**2**	2	2
Termination benefits	**2**	—	—
Share-based payments	**13**	4	8

35. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has other contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2020	2021	2022	2023	2024	2025 and thereafter	Total
Natural gas, transportation and other contracts	125	125	120	128	131	1,493	**2,122**
Transmission	9	5	4	3	—	—	**21**
Coal supply and mining agreements	147	16	16	16	8	14	**217**
Long-term service agreements	50	22	32	17	15	14	**150**
Operating leases	4	2	2	2	3	64	**77**
Growth	535	254	196	270	13	—	**1,268**
TransAlta Energy Transition Bill	6	6	6	6	—	—	**24**
Total	**876**	**430**	**376**	**442**	**170**	**1,585**	**3,879**

A. Natural Gas, Transportation and Other Contracts

Includes fixed price or volume natural gas purchase and transportation contracts. Other contracts relate to commitments for goods and services.

B. Transmission

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements
Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2020.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness joint operation, and certain other mining royalty agreements. Some of these commitments have been reduced due to the cessation of coal-fired emissions from the Sheerness coal-fired plant on or before Dec. 31, 2030.

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

E. Operating Leases
Includes lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Prior to the adoption of IFRS 16 (refer to Note 3(A)(I) for further details), operating lease expenses were recognized as incurred in the statement of earnings. During the year ended Dec. 31, 2018, $8 million (2017 - $7 million) was recognized as an expense in respect of operating leases. Sublease payments received during 2019, 2018 and 2017 were less than $1 million. No contingent rental payments were made in respect of operating leases.

F. Growth
Commitments for growth relate to the following projects: coal-to-gas conversions and repowering Sudance Unit 5, Kaybob cogeneration, Windrise, Windcharger and Skookumchuck and any final costs associated with the Big Level and Antrim projects. Refer to Note 4 for further details on these projects.

G. TransAlta Energy Transition Bill Commitments
As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement, we have committed to fund US$55 million in total over the remaining life of the Centralia 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 of Dec. 31, 2019, the Corporation has funded approximately US$37 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other
A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability, and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies
TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding 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 recalculate loss factors for 2006 to 2016 and issue a single invoice charging or crediting market participants for the difference in losses charges. A more recent decision by the AUC determined the methodology to be used retroactively, which made it possible for the Corporation to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA power generation. The single invoice for the historical adjustments was to be issued in April 2021, with cash settlement expected in June 2021. The current total estimate of exposure based on known data is approximately $12 million. However, the AESO recently requested the AUC approve a pay-as-you-go settlement, instead of issuing a single invoice. This form of settlement would permit the AESO to issue an invoice for each historical year as the line loss factors are recalculated, resulting in invoices being issued as early as April 2020 for settlement in June 2020, a year earlier than anticipated. The Corporation is challenging this request.

II. FMG Disputes

The Corporation is currently engaged in two disputes with FMG. The first dispute arose as a result of FMG's attempted termination of the South Hedland PPA on the basis that the conditions to establishing commercial operation under the South Hedland PPA had not been met. TransAlta's view is that all conditions to establishing commercial operation under the terms of the South Hedland PPA had been satisfied in full. TransAlta initiated legal action against 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. This matter is scheduled to proceed to trial beginning June 15, 2020.

The second dispute involves FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed. A trial date for this matter has not yet been scheduled but it will likely not occur until 2021.

III. Mangrove Claim

On April 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming the Corporation, the incumbent members of the Board on such date, and Brookfield BRP Holdings (Canada), as defendants. Mangrove is alleging, among other things, oppression by the Corporation and the named Directors and is seeking to set aside the 2019 Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter is scheduled to proceed to trial beginning Sept. 14, 2020.

IV. Keephills 1 Superheater

Keephills Unit 1 was taken offline from Mar. 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the PPA. ENMAX Energy Corporation, the purchaser under the PPA at the time, did not dispute the force majeure but the Balancing Pool is attempting to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. TransAlta denied the Balancing Pool had the right to do so. The Alberta Court of Queen's Bench confirmed that the Balancing Pool has a right under the PPA to commence an arbitration, independent of the PPA buyer. On Sept. 4, 2019, the Alberta Court of Appeal upheld the lower court's decision. TransAlta sought permission to appeal the Alberta's Court of Appeal's decision to the Supreme Court of Canada. The application was denied and the matter will now proceed to arbitration, with a hearing potentially sometime in 2020.

V. Sundance A Decommissioning

TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the mine. The Balancing Pool filed a statement of intent to participate as an intervener because it disagrees that, amongst other things, the mine decommissioning costs should be included. TransAlta anticipates it will receive payment from the Balancing Pool in 2020 for its decommissioning costs; however, the amount is uncertain.

VI. Hydro PPA Renewable Energy Credits

The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $27 million, earned by the Hydro plants under the *Carbon Competitiveness Incentive Regulation* in 2018 and 2019. Refer to Note 2(A) and 2(F)(IV) for the accounting policies on these credits. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. The Corporation anticipates this dispute will be resolved by the end of 2021.

VII. Direct Assigned Capital Deferral Account Application
AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 direct assigned capital deferral account for the Edmonton region 240 kV line upgrades project (the "Proceeding"). TransAlta is a secondary applicant in the Proceeding. Altalink and TransAlta seek to have their costs approved by the AUC as reasonable and prudent. The Enoch Cree Nation ("ECN") and the Consumers' Coalition of Alberta are registered participants in the Proceeding. Currently Altalink, ECN and TransAlta's interests are closely aligned. TransAlta believes it has a reasonable chance of having its costs (estimated at about $21 million) approved.

36. Segment Disclosures

A. Description of Reportable Segments

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

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2019	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	816	571	209	160	312	156	129	(6)	2,347
Fuel, carbon compliance and purchased power	570	416	74	9	16	7	—	(6)	1,086
Gross margin	246	155	135	151	296	149	129	—	1,261
Operations, maintenance and administration	138	67	44	37	50	36	30	73	475
Depreciation and amortization	233	83	41	48	124	32	2	27	590
Asset impairment charge (reversal)	15	(10)	—	—	—	2	—	18	25
Gain on termination of Keephills 3 coal rights contract (Note 4(D))	(88)	—	—	—	—	—	—	—	(88)
Taxes, other than income taxes	13	3	1	—	8	3	—	1	29
Termination of Sundance B and C PPAs	(56)	—	—	—	—	—	—	—	(56)
Net other operating expense (income)	(40)	—	(1)	—	(10)	—	—	2	(49)
Operating income (loss)	31	12	50	66	124	76	97	(121)	335
Finance lease income	—	—	6	—	—	—	—	—	6
Net interest expense									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	442	232	165	282	156	67	(7)	2,249
Fuel, carbon compliance and purchased power	666	314	96	8	17	6	—	(7)	1,100
Gross margin	246	128	136	157	265	150	67	—	1,149
Operations, maintenance and administration	171	61	48	37	50	38	24	86	515
Depreciation and amortization	241	74	43	49	110	30	2	25	574
Asset impairment charge	38	—	—	—	12	—	—	23	73
Taxes, other than income taxes	13	5	1	—	8	3	—	1	31
Termination of Sundance B and C PPAs (Note 9)	(157)	—	—	—	—	—	—	—	(157)
Net other operating income	(41)	—	—	—	(6)	—	—	—	(47)
Operating income (loss)	(19)	(12)	44	71	91	79	41	(135)	160
Finance lease income	—	—	8	—	—	—	—	—	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets									1
Earnings before income taxes									(96)

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

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
PP&E	**2,540**	**352**	**392**	**489**	**1,947**	**469**	**1**	**17**	**6,207**
Right of use assets	**68**	**—**	**—**	**4**	**56**	**6**	**—**	**12**	**146**
Intangible assets	**41**	**6**	**2**	**37**	**173**	**5**	**9**	**45**	**318**
Goodwill	—	—	—	—	**176**	**258**	**30**	**—**	**464**

As at Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
PP&E	2,587	332	391	554	1,799	481	1	19	6,164
Intangible assets	81	7	4	41	173	4	11	52	373
Goodwill	—	—	—	—	175	259	30	—	464

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2019	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**114**	**8**	**36**	**6**	**229**	**23**	**—**	**1**	**417**
Intangible assets	**2**	**—**	**—**	**—**	**—**	**—**	**—**	**12**	**14**

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	101	14	21	6	117	16	—	2	277
Intangible assets	3	—	—	—	—	—	—	17	20

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

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	**2019**	2018	2017
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**590**	574	635
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**119**	136	73
Depreciation and amortization on the Consolidated Statements of Cash Flows	**709**	710	708

C. Geographic Information
I. Revenues

Year ended Dec. 31	2019	2018	2017
Canada	**1,460**	1,573	1,663
US	**727**	511	509
Australia	**160**	165	135
Total revenue	**2,347**	2,249	2,307

II. Non-Current Assets

	Property, plant and equipment		Right of use assets		Intangible assets		Other assets		Goodwill	
As at Dec. 31	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018
Canada	**4,854**	4,953	**109**	—	**213**	273	**75**	101	**418**	417
US	**863**	657	**33**	—	**68**	59	**47**	50	**46**	47
Australia	**490**	554	**4**	—	**37**	41	**76**	83	**—**	—
Total	**6,207**	6,164	146	—	**318**	373	**198**	234	**464**	464

D. Significant Customer
During the year ended Dec. 31, 2019, sales to one customer represented 11 per cent of the Corporation's total revenue (2018 - one customer represented 19 per cent).

Exhibit 1
(Unaudited)

The information set out below is referred to as “unaudited” as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2019:

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

1.48 times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2019	2018	2017
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,347**	2,249	2,307
Operating income	**335**	160	138
Net earnings (loss) attributable to common shareholders	**52**	(248)	(190)
STATEMENT OF FINANCIAL POSITION			
Total assets	**9,508**	9,428	10,304
Current portion of long-term debt, net of cash and cash equivalents	**102**	59	433
Credit facilities, long-term debt and finance lease obligations	**2,699**	3,119	2,960
Non-controlling interests	**1,101**	1,137	1,059
Preferred shares	**942**	942	942
Equity attributable to common shareholders[1]	**2,019**	2,055	2,384
Fair value (asset) liability of hedging instruments on debt[1]	**(7)**	(10)	(30)
Total capital[2]	**7,172**	7,275	7,748
CASH FLOWS			
Cash flow from operating activities	**849**	820	626
Cash flow from (used in) investing activities	**(512)**	(394)	87
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**0.18**	(0.86)	(0.66)
Comparable earnings[1]	**n/a**	n/a	n/a
Dividends paid on common shares	**0.12**	0.20	0.16
Book value per common share (at year-end)[1]	**7.14**	7.16	8.28
Market price:			
High	**10.14**	7.90	8.50
Low	**5.50**	5.44	6.88
Close (Toronto Stock Exchange at Dec. 31)	**9.28**	5.59	7.45
RATIOS (percentage except where noted)			
Adjusted net debt to total capital[1]	**49.9**	49.7	49.5
Adjusted net debt to total capital excluding non-recourse debt[1]	**40.7**	39.4	41.8
Adjusted net debt to adjusted comparable EBITDA[1,3,4] (times)	**3.9**	3.6	3.7
Return on equity attributable to common shareholders[1]	**3.3**	(15.8)	(10.0)
Comparable return on equity attributable to common shareholders[1]	**n/a**	n/a	n/a
Return on capital employed[1]	**4.3**	0.7	2.1
Comparable return on capital employed[1]	**n/a**	n/a	n/a
Earnings coverage (times)[1]	**1.5**	0.2	0.6
Dividend payout ratio based on FFO[1,4]	**6.6**	6.1	4.3
Comparable EBITDA[1,3,4] (in millions of Canadian dollars)	**984**	1,123	1,062
Dividend coverage[1,4] (times)	**18.6**	18.3	14.1
Dividend yield[1]	**1.7**	2.9	2.1
Adjusted FFO to adjusted net debt[1,4]	**19.0**	20.8	20.4
FFO before interest to adjusted interest coverage[1,4] (times)	**4.5**	4.8	4.3
Weighted average common shares for the year (in millions)	**283**	287	288
Common shares outstanding at Dec. 31 (in millions)	**277**	285	288
STATISTICAL SUMMARY			
Number of employees	**1,543**	1,883	2,228
Gross installed capacity (MW)[5]			
Coal (Canadian and US)	**4,569**	4,571	5,131
Gas (Canadian and Australian)[6]	**1,395**	1,395	1,403
Renewables (wind, solar and hydro)	**2,421**	2,308	2,289
Equity investments	**—**	—	—
Total generating capacity	**8,385**	8,273	8,823
Total generation production (GWh)	**29,071**	28,409	36,900

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

(1) These items are not defined and have no standardized meaning under IFRS. Periods for which the non-IFRS measure was not previously disclosed have not been calculated. For 2017, comparable earnings measures are no longer being calculated or reported on.

(2) Total invested capital for 2014 to 2009 has been revised to align with the 2015 calculation methodology.

2016	2015	2014	2013	2012	2011	2010	2009
2,397	2,267	2,623	2,292	2,210	2,618	2,673	2,770
478	148	442	195	(214)	645	487	378
117	(24)	141	(71)	(615)	290	255	181
10,996	10,947	9,833	9,624	9,503	9,780	9,635	9,762
334	33	708	175	582	284	202	(51)
3,722	4,408	3,305	4,130	3,610	3,721	3,823	4,411
1,152	1029	594	517	330	358	431	478
942	942	942	781	—	—	—	—
2,569	2,419	2,342	2,125	3,018	3,274	3,120	2,929
(163)	(190)	(96)	(16)	50	32	41	16
8,556	8,641	7,795	7,712	7,590	7,669	7,617	7,783
744	432	796	765	520	690	838	580
(327)	(573)	(292)	(703)	(1,048)	(608)	(765)	(1,598)
0.41	(0.09)	0.52	(0.27)	(2.62)	1.31	1.16	0.90
0.13	(0.17)	0.25	0.31	0.50	1.05	0.97	0.90
0.30	0.72	0.83	1.16	1.16	1.16	1.16	1.16
8.92	8.52	8.52	7.92	8.78	12.08	12.85	13.41
7.54	12.34	14.94	16.86	21.37	23.24	23.98	25.30
3.76	4.13	9.81	12.91	14.11	19.45	19.61	18.11
7.43	4.91	10.52	13.48	15.12	21.02	21.15	23.48
51.0	54.6	56.3	60.7	61.0	52.5	53.1	56.1
44.2	50.2	54.1	58.7	59.0	60.0	50.7	52.6
3.8	5.4	4.2	4.6	4.6	3.8	—	—
5.4	(1.2)	6.3	(3.2)	(25.9)	10.6	9.6	6.9
1.7	(2.3)	3.0	3.7	4.9	8.4	8.0	6.9
5.3	4.6	5.8	2.8	(3.1)	8.3	6.6	5.7
4.4	3.0	5.1	5.2	5.3	7.0	6.0	5.8
1.7	1.5	1.7	0.8	(1.0)	2.7	2.2	1.9
8.1	30.0	26.4	43.1	25.1	24.0	40.0	—
1,144	867	1,036	1,023	1,015	1,044	955	888
11.1	3.3	5.7	6.3	4.7	3.5	4.0	2.6
4.0	14.7	7.9	8.6	7.7	5.5	5.5	4.9
16.3	14.3	16.9	15.2	16.7	20.1	19.6	20.5
3.9	3.7	3.8	3.7	3.3	4.4	4.6	4.9
288	280	273	264	235	222	219	201
288	284	275	268	255	224	220	218
2,341	2,380	2,786	2,772	2,084	2,235	2,389	2,343
5,131	5,126	5,111	5,111	4,551	4,325	4,688	4,967
1,482	1,405	1,531	1,779	1,731	1,567	1,648	1,843
2,334	2,350	2,204	2,202	2,058	1,974	1,950	1,965
—	—	—	396	390	390	390	—
8,947	8,881	8,846	9,488	8,730	8,256	8,676	8,775
38,157	40,673	45,002	42,482	38,750	41,012	48,614	45,736

(3) 2019, 2018 and 2017 amounts were revised as comparable EBITDA was adjusted to exclude the impact of unrealized mark-to-market gains or losses.
(4) 2016 and 2015 amounts were revised due to other revisions to EBITDA or FFO measures in the MD&A.
(5) 2012 to 2019 are gross installed capacity, which reflects the basis of underlying results. Prior year figures are as previously reported.
(6) Includes finance lease receivables.

Ratio Formulas

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

Adjusted net debt to adjusted comparable EBITDA = long-term debt, exchangeable securities and lease obligations including current portion + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / comparable EBITDA - PPA Termination Payments

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

Return on capital employed = earnings (loss) before income taxes + net interest expense - net earnings (loss) attributable to non-controlling interests / total capital - AOCI

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

Dividend payout ratio = common share dividends declared / FFO - 50 per cent dividends paid on preferred shares

Dividend coverage = FFO - cash dividends paid on preferred shares + change in non-cash operating working capital balances / cash dividends paid on common shares

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

Adjusted FFO to adjusted net debt = FFO - PPA Termination Payments - 50 per cent dividends paid on preferred shares / long-term debt, exchangeable securities and lease obligations including current portion + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash

Adjusted FFO before interest to adjusted interest coverage = FFO - PPA Termination payments + interest on debt, exchangeable securities and lease obligations - interest income - capitalized interest / interest on debt, exchangeable securities and lease obligations - interest income + 50 per cent dividends paid on preferred shares

Plant Summary

As of January 2020	Facility	Installed capacity(MW)[1]	Ownership (%)	Owned capacity (MW)[1][2]	Region	Revenue source	Contract expiry date
Coal	Sundance, AB	1,581	100 %	1,581	Western Canada	Merchant[3]	—
11 facilities	Keephills, AB	790	100 %	790	Western Canada	Alberta PPA[4] / Merchant[5]	2020
	Keephills 3, AB	463	100 %	463	Western Canada	Merchant	—
	Sheerness, AB	790	25 %	198	Western Canada	Alberta PPA / Merchant[6]	2020
	Centralia, WA	1,340	100 %	1,340	United States	LTC[7]/Merchant	2020-2025[8]
Total Coal		4,964		4,372			
Gas	Poplar Creek, AB[9]	230	100 %	230	Western Canada	LTC	2030
11 facilities	Fort Saskatchewan, AB	118	30 %	35	Western Canada	LTC	2029
	Sarnia, ON*	499	100 %	499	Eastern Canada	LTC	2022-2025
	Ottawa, ON	74	50 %	37	Eastern Canada	LTC/ Merchant	2020-2033
	Windsor, ON	72	50 %	36	Eastern Canada	LTC/ Merchant	2031
	Parkeston, WA*[11]	110	50 %	55	Australia	LTC	2026
	Southern Cross, WA*[10][11]	245	100 %	245	Australia	LTC	2023
	South Hedland, WA*[11]	150	100 %	150	Australia	LTC	2042
Total Gas		1,498		1,287			
Wind	Summerview 1, AB*	68	100 %	68	Western Canada	Merchant	—
23 facilities	Summerview 2, AB*	66	100 %	66	Western Canada	Merchant	—
	Ardenville, AB*	69	100 %	69	Western Canada	Merchant	—
	Blue Trail, AB*	66	100 %	66	Western Canada	Merchant	—
	Castle River, AB*[12]	44	100 %	44	Western Canada	Merchant	—
	McBride Lake, AB*	75	50 %	38	Western Canada	LTC	2024
	Soderglen, AB*	71	50 %	35	Western Canada	Merchant	—
	Cowley North, AB*	20	100 %	20	Western Canada	Merchant	—
	Sinnott, AB*	7	100 %	7	Western Canada	Merchant	—
	Macleod Flats, AB*	3	100 %	3	Western Canada	Merchant	—
	Melancthon, ON*[13]	200	100 %	200	Eastern Canada	LTC	2026-2028
	Wolfe Island, ON*	198	100 %	198	Eastern Canada	LTC	2029
	Kent Breeze, ON*	20	100 %	20	Eastern Canada	LTC	2031
	Kent Hills, NB*[14]	167	83 %	139	Eastern Canada	LTC	2035
	Le Nordais, QC*	98	100 %	98	Eastern Canada	LTC	2033
	New Richmond, QC*	68	100 %	68	Eastern Canada	LTC	2033
	Wyoming Wind, WY*	140	100 %	140	United States	LTC	2028
	Lakeswind, MN*	50	100 %	50	United States	LTC	2034
	Big Level, PA*	90	100 %	90	United States	LTC	2034
	Antrim, NH*	29	100 %	29	United States	LTC	2039
Total Wind		1,547		1,446			
Solar	Mass Solar, MA*[15]	21	100 %	21	United States	LTC	2032-2035
1 facility							
Total Solar		21		21			
Hydro	Brazeau, AB	355	100 %	355	Western Canada	Alberta PPA	2020
27 facilities	Bighorn, AB	120	100 %	120	Western Canada	Alberta PPA	2020
	Spray, AB	112	100 %	112	Western Canada	Alberta PPA	2020
	Ghost, AB	54	100 %	54	Western Canada	Alberta PPA	2020
	Rundle, AB	50	100 %	50	Western Canada	Alberta PPA	2020
	Cascade, AB	36	100 %	36	Western Canada	Alberta PPA	2020
	Kananaskis, AB	19	100 %	19	Western Canada	Alberta PPA	2020
	Bearspaw, AB	17	100 %	17	Western Canada	Alberta PPA	2020
	Pocaterra, AB	15	100 %	15	Western Canada	Merchant	—
	Horseshoe, AB	14	100 %	14	Western Canada	Alberta PPA	2020
	Barrier, AB	13	100 %	13	Western Canada	Alberta PPA	2020
	Taylor, AB*	13	100 %	13	Western Canada	Merchant	—
	Interlakes, AB	5	100 %	5	Western Canada	Alberta PPA	2020
	Belly River, AB*	3	100 %	3	Western Canada	Merchant	—
	Three Sisters, AB	3	100 %	3	Western Canada	Alberta PPA	2020
	Waterton, AB*	3	100 %	3	Western Canada	Merchant	—
	St. Mary, AB*	2	100 %	2	Western Canada	Merchant	—
	Upper Mamquam, BC*	25	100 %	25	Western Canada	LTC	2025
	Pingston, BC*	45	50 %	23	Western Canada	LTC	2023
	Bone Creek, BC*	19	100 %	19	Western Canada	LTC	2031
	Akolkolex, BC (8)*	10	100 %	10	Western Canada	LTC	2045
	Ragged Chute, ON*	7	100 %	7	Eastern Canada	LTC	2029
	Misema, ON*	3	100 %	3	Eastern Canada	LTC	2027
	Galetta, ON*	2	100 %	2	Eastern Canada	LTC	2030
	Appleton, ON*	1	100 %	1	Eastern Canada	LTC	2030
	Moose Rapids, ON*	1	100 %	1	Eastern Canada	LTC	2030
	Skookumchuck, WA	1	100 %	1	United States	LTC	2020
Total Hydro		948		926			
Total		8,978		8,051			

** TransAlta Renewables Inc. facility.*
(1) Megawatts are rounded to the nearest whole number; columns may not add due to rounding.
(2) Accounts for 100% of TransAlta Renewables assets. As of December 31, 2019. TransAlta owns approximately 60% of the outstanding shares of TransAlta Renewables.
(3) Merchant capacity refers to uprates on unit 3 (15 MW), unit 4 (53 MW), unit 5 (53 MW) and unit 6 (44 MW).
(4) PPA refers to Power Purchase Arrangement.
(5) Merchant capacity refers to uprates on unit 1 (12 MW) and unit 2 (12 MW).
(6) Merchant capacity refers to uprates on unit 1 (10 MW).
(7) LTC refers to Long-Term Contract.
(8) Contract is in place until 2025; however, one unit is set to retire in 2020.
(9) The Poplar Creek plant is operated by Suncor and ownership of the facility will transfer to Suncor in 2030.
(10) Comprised of four facilities.
(11) Gas/diesel.
(12) Includes seven individual turbines at other locations.
(13) Comprised of two facilities.
(14) Comprised of three facilities.
(15) Comprised of four ground-mounted projects and four roof-top projects.

Sustainability Performance Indicators

Corporate Statistics

Environment Health & Safety Management Systems	2019	2018	2017
Facilities with ISO 14001 and/or OHSAS 18001-based management systems (percentage)[1]	97	97	97
Management system audits[2]	12	17	20

Environmental Performance	2019	2018	2017
Resource or energy use[3]			
Coal combustion (tonnes)	9,091,700	10,001,100	14,956,400
Natural gas combustion (GJ)	76,647,600	62,354,800	55,519,800
Diesel combustion (L)	10,173,900	9,552,800	4,384,700
Gasoline consumption: vehicle (L)	1,138,400	1,424,000	1,476,700
Diesel consumption: vehicle (L)	21,532,400	38,361,500	44,045,200
Propane consumption: vehicle (L)	95,900	75,100	112,000
Electricity: building operations (MWh)	211,100	279,800	290,100
Natural gas: building operations (GJ)	53,400	73,100	75,500
Propane: building operations (L)	169,400	154,300	125,800
Kerosene: building operations (L)	83,800	115,600	96,200
Total resource or energy use (GJ)[4]	345,198,900	**358,460,000**	**496,909,620**
Greenhouse gas emissions[5]			
Carbon dioxide (tonnes CO_2e) √	20,410,800	20,589,700	29,624,500
Methane (tonnes CO_2e) √	52,900	69,300	107,100
Nitrous oxide (tonnes CO_2e) √	110,600	115,500	185,100
Sulfur hexafluoride (tonnes CO_2e)	70	10	10
Total greenhouse gas emissions[6] (tonnes CO_2e) √	20,574,400	**20,774,600**	**29,916,700**
Greenhouse gas emission intensity[7] (tonnes CO_2e / MWh) √	*0.75*	*0.77*	*0.86*
Scope 1 emissions (% of total GHG emissions)	99	99	99
Scope 2 emissions (% of total GHG emissions)	1	1	1
Scope 1 emissions reported to national regulatory bodies (%)	100	100	100
Air emissions[8]			
Total sulphur dioxide emissions (tonnes) √	15,900	19,300	36,200
Sulphur dioxide emission intensity[9] (kg / MWh) √	*0.58*	*0.73*	*1.05*
Total nitrogen oxide emissions (tonnes) √	25,800	28,000	44,400
Nitrogen oxide emission intensity[9] (kg / MWh) √	*0.95*	*1.05*	*1.29*
Total particulate matter emissions (tonnes) √	8,200	8,400	11,400
Particulate matter emission intensity[9] (kg / MWh) √	*0.30*	*0.31*	*0.33*
Total mercury emissions (kilograms) √	60	70	110
Mercury emission intensity[9] (mg / MWh) √	*2.36*	*2.50*	*3.29*
Water management[10]			
Water withdrawal - water utility/municipality/customer (million m^3)	*2*	*1*	*1*

Water withdrawal - surface water (million m^3)	*284*	*244*	*210*
Water withdrawn - all sources (million m^3) √	286	245	211
Water discharge - all sources (million m^3) √	218	208	172
Water consumption (million m^3) √	68	**37**	**39**
Water intensity (m^3/MWh)(11) √	*2.48*	*1.40*	*1.13*
Waste management			
Non-hazardous(12)			
Landfill (tonnes) √	900	1,900	3,200
Landfill (L) √	34,700	68,100	63,500
Ash disposal: mine (tonnes) (13) √	641,400	715,100	1,338,600
Ash disposal: lagoon (tonnes) (14) √	117,400	276,900	485,500
Recycled (tonnes) √	3,100	1,800	1,400
Recycled (L) √	3,605,400	3,721,700	4,122,700
Reuse (tonnes) √	745,200	560,800	827,400
Storage (tonnes) √	—	—	—
Hazardous(15)			
Landfill (tonnes) √	60	10	40
Landfill (L) √	52,500	45,100	14,600
Recycled (tonnes) √	80	200	12,700
Recycled (L) √	18,945,300	16,255,300	20,140,400
Land use and reclamation			
Land used in mining activities – disturbed (cumulative hectares) √	12,600	12,400	12,100
Land used in mining activities – reclaimed (cumulative hectares) √	4,800	4,700	4,600
Land reclamation (% of land disturbed) √	*38*	***38***	***38***
Land used in mining activities: disturbed minus reclaimed (hectares) √	7,700	7,700	7,400
Land used by plants, offices and equipment (hectares) √	3,900	3,900	3,900
Total land use (cumulative hectares) √	11,700	**11,700**	**11,300**
Environmental incidents(16)			
Total environmental incidents √	9	7	5
Significant environmental incidents	3	1	2
Regulatory non-compliance environmental incidents	6	6	3
Environmental enforcement actions(17)	1	1	—
Environmental fines ($ thousands)	4	6	—
Spills(18)			
Volume of significant spills (m^3)	530	5	15

Social Performance	2019	2018	2017
Workplace practices			
Employees	1,543	1,883	2,228
Number of full-time employees	*1,471*	*1,810*	*2,125*
Number of part-time employees	*18*	*22*	*24*
Number of contingent employees	*54*	*51*	*79*
Employees represented by independent trade union organizations[19] (%)	45	50	57
Voluntary employee turnover rate[20] (%)	13.59	20.22	10.65
Diversity			
Women in workforce (% of all employees)	20	20	19
Women in senior management (%)	50	50	26
Women on Board of Directors (%)	33	40	40
Health and safety			
Health and safety enforcement actions[21]	3	—	4
Health and safety fines ($ thousands)	—	—	—
Employee & contractor fatalities √	—	—	—
Lost-time incident (LTI) (absence from work)[22] √	5	1	6
Medical aid (MA) incidents (no absence from work)[23] √	7	12	15
First Aid (FA) incidents (no absence from work)[24] √	8	23	67
Restricted Work Injuries (RWI) incidents (no absence from work)[25] √	3	12	16
Total injuries to employees & contractors √	23	48	104
Total Injury Frequency (TIF) (employees and contractors)[26] √	1.12	1.91	3.42
Total Recordable Injury Frequency (TRIF) (employees and contractors)[27]	0.73	1.00	1.22
Community relations			
Community investments ($ millions)[28]	2.1	2.4	2.6

√ 2019 Data has been third-party assured to a limited assurance level by Ernst & Young LLP.
Please see "Discussion and Notes on Numbers" for footnote explanations.

Alignment of Sustainability Performance Indicators with Leading Environment, Social and Governance Frameworks

Environment Health & Safety Management Systems	Global Reporting Index ("GRI")	SustainabilityAcounting Standards Board ("SASB")
Facilities with ISO 14001 and/or OHSAS 18001-based management systems (percentage)		
Management system audits		

Environmental Performance	GRI	SASB
Resource or energy use	302-1	
Coal combustion (tonnes)	302-1	
Natural gas combustion (GJ)	302-1	
Diesel combustion (L)	302-1	
Gasoline consumption: vehicle (L)	302-1	
Diesel consumption: vehicle (L)	302-1	
Propane consumption: vehicle (L)	302-1	
Electricity: building operations (MWh)	302-1	
Natural gas: building operations (GJ)	302-1	
Propane: building operations (L)	302-1	
Kerosene: building operations (L)	302-1	
Total resource or energy use (GJ)	302-1	
Greenhouse gas emissions		
Carbon dioxide (tonnes CO_2e)	305-1, 305-2, 305-3	IF-EU-110a.1.
Methane (tonnes CO_2e)	305-1, 305-2, 305-3	IF-EU-110a.1.
Nitrous oxide (tonnes CO_2e)	305-1, 305-2, 305-3	IF-EU-110a.1.
Sulfur hexafluoride (tonnes CO_2e)	305-1, 305-2, 305-3	IF-EU-110a.1.
Total greenhouse gas emissions (tonnes CO_2e)	305-1, 305-2, 305-3	
Greenhouse gas emission intensity (tonnes CO_2e / MWh)	*305-4*	
Scope 1 emissions (% of total GHG emissions)	305-1	IF-EU-110a.1.
Scope 2 emissions (% of total GHG emissions)	305-2	
Scope 1 emissions reported to national regulatory bodies (%)		IF-EU-110a.1.
Air emissions		
Total sulphur dioxide emissions (tonnes)	305-7	IF-EU-120a.1.
Sulphur dioxide emission intensity (kg / MWh)		
Total nitrogen oxide emissions (tonnes)	305-7	IF-EU-120a.1.
Nitrogen oxide emission intensity (kg / MWh)		
Total particulate matter emissions (tonnes)	305-7	IF-EU-120a.1.
Particulate matter emission intensity (kg / MWh)		
Total mercury emissions (kilograms)	*305-7*	IF-EU-120a.1.
Mercury emission intensity (mg / MWh)		
Water management		
Water withdrawal - water utility/municipality/customer (million m^3)	303-3	IF-EU-140a.1.

Water withdrawal - surface water (million m^3)	303-3	IF-EU-140a.1.
Water withdrawn - all sources (million m^3)	303-3	IF-EU-140a.1.
Water discharge - all sources (million m^3)	303-4	
Water consumption (million m^3)		**IF-EU-140a.1.**
Water intensity (m^3/MWh)		
Waste management		
Non-hazardous		
Landfill (tonnes)	306-2	
Landfill (L)		
Ash disposal: mine (tonnes)	306-2	
Ash disposal: lagoon (tonnes)	306-2	
Recycled (tonnes)	306-2	
Recycled (L)		
Reuse (tonnes)	306-2	IF-EU-150a.1.
Storage (tonnes)	306-2	
Hazardous		
Landfill (tonnes)	306-2	
Landfill (L)		
Recycled (tonnes)	306-2	
Recycled (L)		
Land use and reclamation		
Land used in mining activities – disturbed (cumulative hectares)	304-1	
Land used in mining activities – reclaimed (cumulative hectares)	304-1	
Land reclamation (% of land disturbed)	*304-3*	
Land used in mining activities: disturbed minus reclaimed (hectares)	304-1	
Land used by plants, offices and equipment (hectares)	304-1	
Total land use (cumulative hectares)	304-1	
Environmental incidents		
Total environmental incidents	307-1	
Significant environmental incidents	307-1	
Regulatory non-compliance environmental incidents	307-1	
Environmental enforcement actions	307-1	
Environmental fines ($ thousands)	307-1	
Spills		
Volume of significant spills (m^3)	306-3	

Social Performance	GRI	SASB
Workplace practices		
Employees	102-7	
Number of full-time employees		
Number of part-time employees		
Number of contingent employees		
Employees represented by independent trade union organizations (%)	102-41	
Voluntary employee turnover rate (%)		
Diversity		
Women in workforce (% of all employees)	405-1	
Women in senior management (%)	405-1	
Women on Board of Directors (%)	405-1	
Health and safety		
Health and safety enforcement actions		
Health and safety fines ($ thousands)		
Employee & contractor fatalities	403-9	IF-EU-320a.1.
Lost-time incident (LTI) (absence from work)		IF-EU-320a.1.
Medical aid (MA) incidents (no absence from work)		IF-EU-320a.1.
First Aid (FA) incidents (no absence from work)		IF-EU-320a.1.
Restricted Work Injuries (RWI) incidents (no absence from work)		IF-EU-320a.1.
Total injuries to employees & contractors		IF-EU-320a.1.
Total Injury Frequency (TIF) (employees and contractors)		
Total Recordable Injury Frequency (TRIF) (employees and contractors)		IF-EU-320a.1.
Community relations		
Community investments ($ millions)	201-1	

Discussion and Notes on Numbers

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

1. *ISO 14001 and ISO 18001 are the world's most recognized standards for Environmental Management and Health and Safety Management systems. TransAlta has ownership in 73 facilities.*
2. *Internal audits are conducted against ISO management systems, regulatory frameworks and the Alberta Certificate of Recognition standard.*
3. *Energy use is calculated and reported from TransAlta-operated facilities, following the same approach we use for greenhouse gas (GHG) emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard.*
4. *A number of 2017 and 2018 historical energy use volumes from our natural gas business unit were revised in 2019. Minor adjustments to gas, diesel and oils volumes from 2017 and 2018 at Fort Saskatchewan, Ottawa and Windsor were made. These changes were due to data system errors.*
5. *GHG emissions are calculated and reported from TransAlta-operated facilities in line with carbon regulations where the facility is located and with The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (specifically 'Setting Organizational Boundaries: Operational Control' methodology). As per the operational control methodology, TransAlta reports 100 per cent of GHG emissions from facilities at which we are the operator. GHG emissions include emissions from stationary combustion, transportation use, building use and fugitive emissions. We report both scope 1 and scope 2 emissions. An estimate of our scope 3 emissions can be found in our 2019 MD&A and our 2019 CDP climate change report.*
6. *Gross GHG emissions or gross carbon dioxide equivalent (CO_2e) emissions is the sum of carbon dioxide, methane, nitrous oxide and sulfur hexafluoride. Consequently, the sum of scope 1 and 2 emissions will equate to gross CO_2e emissions or gross GHG emissions. Minor adjustments were made to historical 2017 and 2018 GHG emissions data from our natural gas business units as a result of adjusted historical energy use volumes.*
7. *GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*
8. *Air emissions are calculated and reported from TransAlta-operated facilities, following the same approach we use for greenhouse gas (GHG) emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. Air emissions are expressed in tonnes, except for mercury emissions, which are represented in kilograms. Total particulate matter emissions (TPM) include both $PM_{2.5}$ and PM_{10}. In 2019, we revised our historical TPM emissions to reflect our road dust emissions reported to the National Pollutant Release Inventory in 2018. 2018 marked our first year estimating and reporting road dust TPM emissions from our Highvale coal mine in Alberta. We have applied road dust TPM estimates to 2017 and 2019, which are based on our 2018 reported road dust TPM emissions.*
9. *Air emission intensities are calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. Historical adjustments to 2017 and 2018 TPM emissions (see Note 8) also resulted in adjustments to TPM emission intensity data.*
10. *Water use is calculated and reported from TransAlta-operated facilities, following the same approach we use for greenhouse gas (GHG) emissions reporting, which is the application of an 'Operational Control' boundary as per guidance from the Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. Total water consumed is measured by total water withdrawal minus water discharge. Water is used primarily for cooling by our thermal power plants. Evaporative losses from cooling ponds and cooling towers account for the majority of consumptive loss. The water lost to evaporation is not returned directly to the water body, but the water remains in the hydrologic cycle. Historical 2017 Australia natural gas fleet water volumes were adjusted in 2019 to reflect miscalculation by the business unit (rounding errors).*
11. *Water intensity is calculated by dividing total operational water consumption (m^3) by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*
12. *Non-hazardous waste includes, but is not limited to, the disposal of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. Minor adjustments were made to historical 2018 non-hazardous waste volumes to reflect incorporation of missing waste vendor information from 2018.*
13. *Ash disposal: mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal. Historical 2018 volumes were adjusted in 2019 to reflect misreported volumes from 2018.*
14. *Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.*
15. *Hazardous wastes can be harmful to people, plants, animals or the environment, either in the short or the long term, and TransAlta is required in all of its operating jurisdictions to follow proper procedures for landfill/recycling of these materials.*
16. *Our environmental incident reporting was revised in 2019. Environmental incidents are now separated into two categories: significant environmental incidents and regulatory non-compliance environmental incidents. We define regulatory non-compliance environmental incidents as events that involved a non-compliance event but did not have an impact on the environment. For example, a technical issue with a computer system for gathering real-time data could cause us to be out of compliance with local regulation or our EMS, but there is no direct consequence for the physical environment. All other events are captured as significant environmental incidents and these are where we deem there to be a material impact to the environment.*
17. *Environmental enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.*
18. *Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare that we experience large spills, which would adversely impact the environment and the Corporation.*
19. *TransAlta has approximately 700 unionized workers working primarily in our operational business units.*
20. *Voluntary turnover is aligned with our Human Resources voluntary turnover reporting methodology. As per this methodology, voluntary turnover is any full-time, part-time or contingent employee initiated exit, excluding retirement. Summer students and temporary workers are not considered within voluntary turnover.*
21. *Health and safety enforcement actions are a violation or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.*
22. *Lost-time injuries (LTIs) are injuries that resulted in the worker being away from work beyond the day of the injury.*
23. *Medical aids (MAs) are injuries that resulted in medical treatment beyond first aid.*
24. *First Aids (FAs) are an injury that is limited to treatment of minor scratches, cut, scrapes, burns, splinters, etc. which does not require further medical treatment.*
25. *Restricted work injuries (RWIs) are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.*
26. *Total Injury Frequency (TIF) tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids).*
27. *Total Recordable Injury Frequency (TRIF) measures restricted work, medical aid and lost time injuries per 200,000 hours worked.*
28. *Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.*

Independent Sustainability Assurance Statement

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

Scope of Ernst & Young LLP ("EY") Engagement
Our responsibilities included providing limited assurance over a selection of performance indicators as presented in the Addendum to this statement.

Subject Matter
We have performed limited assurance procedures for the following quantitative performance indicators ("Subject Matter") for the year ending December 31, 2019:

- Carbon dioxide emissions (tonnes CO2e)
- Methane emissions (tonnes CO2e)
- Nitrous oxide emissions (tonnes CO2e)
- Total greenhouse gas emissions and emissions intensity (tonnes CO2e, tonnes CO2e/MWh)
- Sulphur dioxide emissions and emission intensity (tonnes, kg/MWh)
- Nitrogen oxide emissions and emission intensity (tonnes, kg/MWh)
- Particulate matter emissions and emission intensity (tonnes, kg/MWh)
- Mercury emissions and emission intensity (kg, mg/MWh)
- Waste Management – Non-hazardous
- Landfill (tonnes, L)
- Ash Disposal: mine, lagoon (tonnes)
- Recycled (tonnes, L)
- Reuse (tonnes)
- Storage (tonnes)
- Waste Management – Hazardous
- Landfill (tonnes, L)
- Recycled (tonnes, L)
- Water Withdrawal (million m3)
- Water Discharge (million m3)
- Water Consumption and consumption intensity (million m3, m3/MWh)
- Mining land use – disturbed (Ha)
- Mining land use – reclaimed (Ha)
- Mining land use - % of land disturbed
- Mining land use – disturbed minus reclaimed (Ha)
- Plants, offices and equipment land use (Ha)
- Total land use (Ha)
- Employee and contractor fatalities
- Lost time incidents for employees and contractors
- Medical aids for employees and contractors
- Restricted work injuries for employees and contractors
- First aids for employees and contractors
- Total TIF injuries to employees and contractors
- Total incident frequency for employees and contractors (incidents/200,000 hours)
- Total environmental incident

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

TransAlta Management Responsibilities
The Subject Matter was prepared by the management of TransAlta, which is responsible for the assertions, statements and claims made therein including the assertions we have been engaged to provide limited assurance over, collection, quantification and presentation of the performance indicators and the criteria used in determining that the information is appropriate for the purpose of disclosure in this Report ("the Report"). In addition, management is responsible for maintaining adequate records and internal controls that are designed to support the reporting process.

EY Responsibilities
Our limited assurance procedures have been planned and performed in accordance with the International Standard on Assurance Engagements 3000 Assurance Engagements other than Audits or Reviews of Historical Financial Information.

Our procedures were designed to obtain a limited level of assurance on which to base our conclusion. The procedures conducted do not provide all the evidence that would be required in a reasonable assurance engagement and, accordingly, we do not express a reasonable level of assurance. While we considered the effectiveness of management's internal controls when determining the nature and extent of our procedures, our assurance engagement was not designed to provide assurance on internal controls and, accordingly, we express no conclusions thereon.

This assurance statement has been prepared for TransAlta for the purpose of assisting management in determining whether the Subject Matter is in accordance with the criteria and for no other purpose. Our assurance statement is made solely to TransAlta in accordance with the terms of our engagement. We do not accept or assume responsibility to anyone other than TransAlta for our work, or for the conclusions we have reached in this assurance statement.

Assurance Procedures
We planned and performed our work to obtain all the evidence, information and explanations considered necessary in relation to the above scope. Our assurance procedures included but were not limited to:

- Interviewing relevant personnel at the head office and at various sites to understand data management processes related to the selected performance indicators.
- Checking the accuracy of calculations performed - on a test basis - primarily through inquiry, variance analysis and performance of re-calculations.
- Assessing risk of material misstatement due to fraud or errors relating to the selected performance indicators.
- Evaluating the overall presentation of the Report, including the consistency of the Subject Matter.

Limitations of EY Work Performed
Our scope of work did not include expressing conclusions in relation to:

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

Independence and Competency Statement
In conducting our engagement, we have complied with the applicable requirements of the Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants.

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

Ernst + Young LLP

Chartered Professional Accountants
Calgary, Canada
Mar. 3, 2020

Shareholder Information

Special Services for Registered Shareholders

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

Stock Splits and Share Consolidations

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

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

Dividend Declaration for Common Shares

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

Common Share Dividends Declared in 2019

Payment Date	Record Date	Ex-Dividend Date	Dividend
July 1, 2019	June 3, 2019	May 31, 2019	$0.04
Oct. 1, 2019	Sept. 3, 2019	Aug. 30, 2019	$0.04
Jan. 1, 2020	Dec. 2, 2019	Nov. 29, 2019	$0.04

Submission of Concerns Regarding Accounting or Auditing Matters

TransAlta has adopted a procedure for employees, shareholders or others to report concerns or complaints regarding accounting or other matters on an anonymous, confidential basis to the Audit, Finance and Risk Committee of the Board of Directors. Such submissions may be directed to the Audit and Risk Committee c/o the Chief Officer, Legal, Regulatory and External Affairs of the Corporation.

Dividend Declaration for Preferred Shares

Series A: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $0.67724 per share from and including March 31, 2016, to, but excluding March 31, 2021.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2016, to but excluding March 31, 2021.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.01 per share from and including June 30, 2017, to, but excluding June 30, 2022.

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

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.247 per share from and including September 30, 2019, to, but excluding Sept. 30, 2024.

Preferred Share Dividends Declared in 2019

Series A			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Jun. 30, 2019	Jun. 3, 2019	May 31, 2019	$0.16931
Sept. 30, 2019	Sept. 3, 2019	Aug, 31, 2019	$0.16931
Dec. 31, 2019	Dec. 2, 2019	Nov. 29, 2019	$0.16931
Series B			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Jun. 30, 2019	Jun. 3, 2019	May 31, 2019	$0.23136
Sept. 30, 2019	Sept. 3, 2019	Aug, 31, 2019	$0.23422
Dec. 31, 2019	Dec. 2, 2019	Nov. 29, 2019	$0.23113
Series C			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Jun. 30, 2019	Jun. 3, 2019	May 31, 2019	$0.25169
Sept. 30, 2019	Sept. 3, 2019	Aug, 31, 2019	$0.25169
Dec. 31, 2019	Dec. 2, 2019	Nov. 29, 2019	$0.25169
Series E			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Jun. 30, 2019	Jun. 3, 2019	May 31, 2019	$0.32463
Sept. 30, 2019	Sept. 3, 2019	Aug, 31, 2019	$0.32463
Dec. 31, 2019	Dec. 2, 2019	Nov. 29, 2019	$0.32463
Series G			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
Jun. 30, 2019	Jun. 3, 2019	May 31, 2019	$0.33125
Sept. 30, 2019	Sept. 3, 2019	Aug, 31, 2019	$0.33125
Dec. 31, 2019	Dec. 2, 2019	Nov. 29, 2019	$0.31175

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

Voting Rights
Common shareholders receive one vote for each common share held.

Annual Meeting
The Annual and Special Meeting of Shareholders will be held at 10:30 a.m. MST, on Tuesday, April 21, 2020, at the BMO Centre (Stampede Park) 20 Roundup Way SE, Calgary, Alberta.

Transfer Agent
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Exchanges
Toronto Stock Exchange (TSX)
New York Stock Exchange (NYSE)

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

Additional Information
Requests can be directed to:
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Shareholder Highlights

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

Year ended Dec. 31 *($)*

	10	11	12	13	14	15	16	17	18	19
TransAlta	100	105	81	78	65	33	51	52	40	68
S&P/TSX	100	91	98	111	122	112	136	149	135	166

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2009 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet

Ten-Year Market Value vs. Book Value

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

	10	11	12	13	14	15	16	17	18	19
Market Value	21.15	21.02	15.12	13.48	10.52	4.91	7.43	7.45	5.59	9.28
Book Value	12.85	12.08	8.78	7.92	8.52	8.52	8.92	8.28	7.16	7.14

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

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2019

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	15	12	22	16	16	15	9	8	9	8	11	11
TSX closing price *($ per share)*	7.17	8.01	9.82	9.04	8.94	8.52	8.09	8.57	8.62	7.78	8.96	9.28

Source: FactSet

Return on Common Shareholders' Equity

(%)

	10	11	12	13	14	15	16	17	18	19
ROE	9.6	10.6	(25.9)	(3.2)	6.3	(1.2)	5.4	(10.0)	(15.8)	3.3

Source: TransAlta

Corporate Information

Corporate Governance: New York Stock Exchange Disclosure Differences

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

Ethics Helpline

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

The Ethics Helpline phone number is **1.855.374.3801** (US/Canada) and **1.800.339276** (Australia)
Internet portal: **transalta.ethicspoint.com**
Email: **TA_ethics_helpline@transalta.com**

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

TransAlta Corporate Officers

Dawn L. Farrell
President and Chief Executive Officer

Todd Stack
Chief Financial Officer

Jane N. Fedoretz
Chief Talent & Transformation Officer

Brett M. Gellner
Chief Development Officer

John H. Kousinioris
Chief Operating Officer & President of TransAlta Renewables Inc.

Dawn E. de Lima
Chief Shared Services Officer

Kerry O'Reilly Wilks
Chief Officer, Legal, Regulatory and External Affairs

Wayne A. Collins
Executive Vice-President, Generation

Aron J. Willis
Senior Vice-President, Growth

Blain Van Melle
Senior Vice-President, Trading and Commercial

Kathryn Higgins
Managing Director and Corporate Controller

Brent Ward
Managing Director, Treasury & Chief Financial Officer of TransAlta Renewables Inc.

Scott T. Jeffers
Managing Director, Corporate Secretary

Glossary of Key Terms

Alberta Hydro Assets
The Corporation's hydro assets located in Alberta consisting of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro generation facilities.

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

Ancillary Services
As defined by the *Electric Utilities Act*, Ancillary Services are those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency.

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

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

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

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

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

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

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

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

Gigajoule (GJ)
A metric unit of energy commonly used in the energy industry. One GJ equals 947,817 British Thermal Units (Btu). One GJ is also equal to 277.8 kilowatt hours ("kWh").

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

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

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

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

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

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

Merchant
A term used to describe assets that are not contracted and are exposed to market pricing.

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

Pioneer Pipeline
The Pioneer gas pipeline jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd.

PPA Termination Payments
The Balancing Pool terminated the Sundance B and C Power Purchase Arrangements and as a result paid TransAlta $157 million in the first quarter of 2018 as well as an additional $56 million (plus GST and interest) on winning the arbitration against the Balancing Pool in the third quarter of 2019. Refer to the Significant and Subsequent Events section for further details.

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

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

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

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

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

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

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

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TransAlta™