TransAlta

Our E^{2}SG Advantage

TransAlta Corporation

2020 Annual Integrated Report

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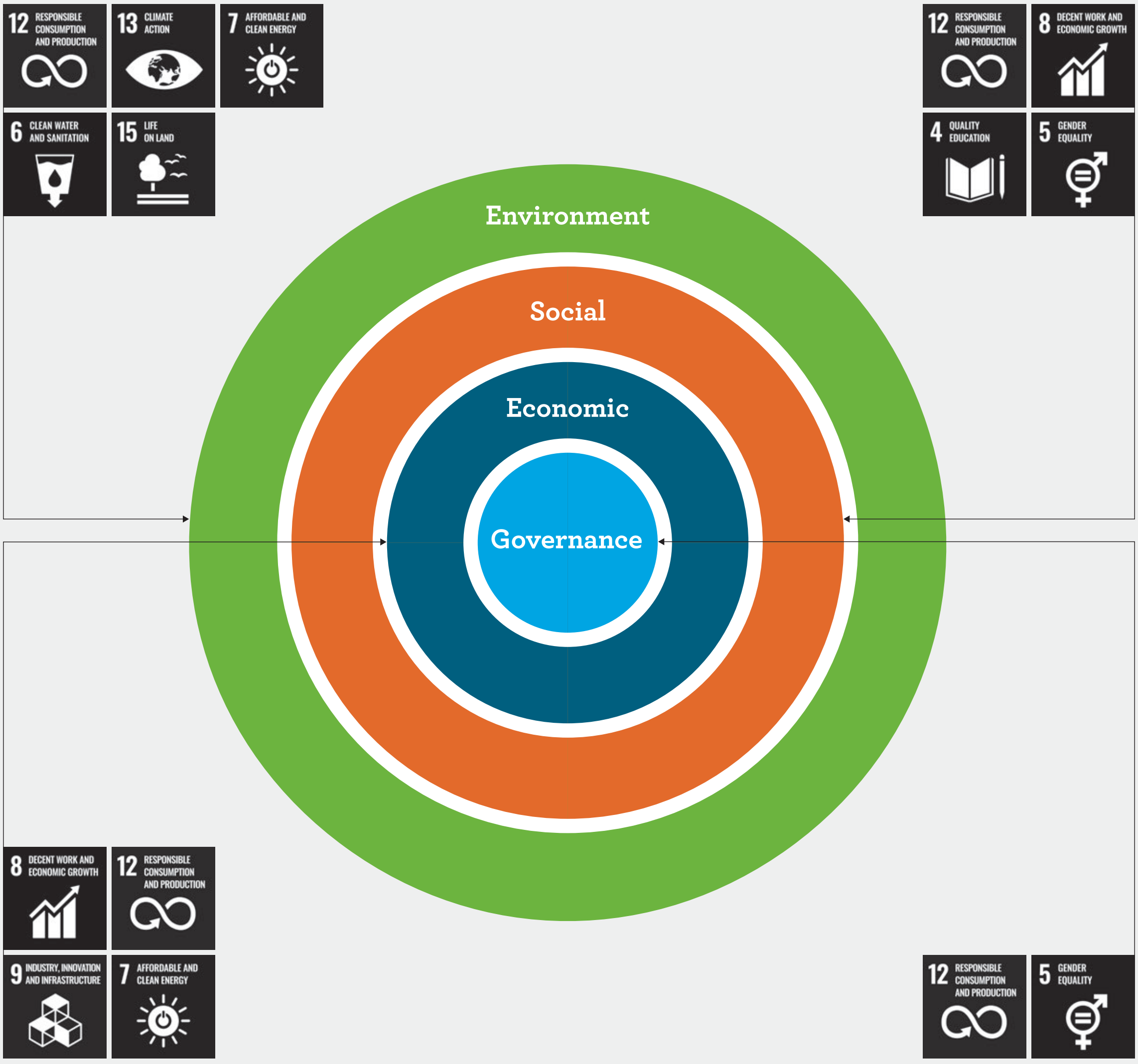
E²SG is more than simply a business strategy at TransAlta, it's a competitive advantage. Sustainability, or ESG, is one of our core values: it is part of our corporate culture and is a top priority. We strive to integrate sustainability into governance, decision-making, risk management and our day-to-day to business processes, while balancing growth considerations and the economy, and that's why we put the extra E in ESG — E²SG. The outcome of our sustainability focus is continuous improvement on key ESG issues and ensuring our economic value creation is balanced with a value proposition for the environment and for people.



TransAlta aligns its ESG goals to the United Nations Sustainable Development Goals to ensure our goals and targets are supportive of solving key global ESG issues. Learn more at www.un.org/sustainabledevelopment/sustainable-development-goals

Letter to Shareholders

The events of this year were unexpected and challenging, bringing with them moments of deep concern over what the future might hold. Yet step by step and hour by hour, the TransAlta team faced into every fact we could gather and took the necessary measures to keep the company strong, our people safe and our customers served.

As shareholders, you can be proud of how we are handling the COVID-19 pandemic and how we have positioned the Company for 2021 and beyond. We finished 2020 with strong financial and operational performance and we made significant progress to deliver on the strategies that are transforming our future.

On February 4, 2021, our Board of Directors announced my retirement from TransAlta effective March 31, 2021, and the appointment of John Kousinioris as our new CEO effective April 1. I am thrilled that the Board appointed John as our new CEO and supported his appointment wholeheartedly. John and I have worked together for over eight years and he has proven himself to be a respected and well-rounded leader capable of deftly navigating the ship over the next decade. He is ready to take the company into what will be an exciting time as clean electricity takes on an even more prominent and important role in fuelling our lives.

The year was marked by the resilience of our people, the performance of our diversified portfolio of investments and progress on our E^2SG (economic, environment, social and governance) goals. Growing our investments in TransAlta Renewables and continuing with our investments in the transition off coal in Alberta have strengthened TransAlta's overall E^2SG framework. Together, our strategic investments, ownership of the hydro assets in Alberta and positioning in competitive gas-fired generation have set us up as a strong E^2SG holding in your portfolio.

Strong Performance

Despite the challenges of the year, the TransAlta team delivered strong free cash flow of $358 million, proving once again the value of our diversified portfolio. This year, exceptional performance by our US operations and our trading floor offset the impact of COVID-19 on our Alberta operations.

Our free cash flow results of $1.31 per share were excellent, especially considering that our Alberta thermal business was down $159 million on a free cash flow basis compared to 2019 due to the province's economic downturn. In 2020, we returned $61 million of capital to shareholders by purchasing and cancelling 7.35 million common shares at an average price of $8.33 per share through our normal course issuer bid program.

Our share price climbed from $9.28 to over $9.67 this year and continued upward in early 2021 as investors realized that TransAlta has tremendous value in its portfolio. We also grew the dividend by six per cent for the second year. In October, we received our second instalment of the Brookfield financing and repaid $400 million of 2020 debt maturity. Now that we have completed our deleveraging program, the future is about returning capital to shareholders and funding our growth.

> The year was marked by the resilience of our people, the performance of our diversified portfolio of investments and progress on our E^{2}SG (economic, environment, social and governance) goals.

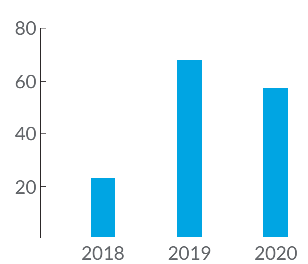
Our key indicator for safety performance is Total Injury Frequency and we set our 2020 goal as 1.17 — which is top-quartile performance. We achieved 1.67 — much higher than planned — where higher means worse performance. We set a goal and missed our target. Failures like these at TransAlta motivate all of us to do better, and we will diligently pursue improvement in 2021 for our safety culture. On a positive note, for Total Safety Reporting we recorded 40 per cent more observations for hazard and near miss reporting compared to 2019. Adjusted availability was 90.3 per cent, ahead of our 2019 performance of 90 per cent.

As I mentioned above, we experienced massive demand destruction in our Alberta business as COVID-19 profoundly impacted the provincial economy. By mid-March, almost 450 MW of load disappeared as businesses shut down and people went home to work. Into May, the loss of load grew to 1,000 MW as the drop in oil prices led to oil and gas production shut-ins as the sector tried to protect margins. Annual Alberta merchant market prices were $8 per megawatt hour lower than expected due to this demand destruction, and sales of megawatts to the grid were hit hard. But we continued to maintain a strong financial position through 2020 due to terrific hedging work by our team and strong performance at Centralia and in our energy marketing segment. Our diversified portfolio paid off, and by November 2020, all but 150 MW of load had come back in Alberta.

In May, we decided to pull back on our growth goals, primarily so we could conserve cash in case the impacts of COVID-19 affected our customers harder than expected. Luckily, through the year, all customers paid their bills on time and we were only hit slightly on our collections. However, we ended 2020 with much stronger liquidity than expected and by year-end we had access to $2.1 billion in liquidity, including $703 million of cash and cash equivalents.

NCIB Repurchase of Common Shares

($ millions)



$61 million

Capital Returned to Shareholders in 2020

Through continued capital allocation discipline

Delivering Strategy

We have reduced our greenhouse gas emissions by 61 per cent since 2005, which is more than any country in the world on a percentage change basis. Our gas conversion strategy means our greenhouse gas emissions are now down to just over 16 tonnes from 42 million tonnes in 2005. By the end of 2030, our emissions will be 12.5 million tonnes, an approximate 70 per cent reduction from our 2005 levels. TransAlta has made significant progress on reducing greenhouse gas emissions, which puts us at the top of the list for ESG investors.

The team delivered on our strategy in 2020. We continued to advance our conversion to gas program, and on February 1, 2021, we announced the final return to service for Sundance Unit 6, which now fires exclusively on gas. At the end of 2020, we retired Unit 1 at our Centralia facility in Washington to uphold our commitment under the Energy Transition Bill with the state. The deal that was struck in 2011 allowed us to keep both units running, free of carbon liability, in return for certain shutdown dates of the end of 2020 for Unit 1 and 2025 for Unit 2. Unit 1 ran for 20 years under our ownership, logged over 9.2 million person-hours and kept hundreds of people employed over two decades.

In November, we affirmed our commitment to proceed with the Sundance 5 repowering project in Alberta, which will convert an existing thermal coal unit into a highly efficient combined-cycle natural gas generating facility. The Sundance Unit 5 repowering project received approval from the company's Board of Directors and is on track to reach commercial operation by the fourth quarter of 2023.

We announced that we will discontinue mining operations at our Alberta Highvale coal mine at the end of 2021. This means that Keephills Unit 1 and Sundance Unit 4 will no longer run on coal, and will only run on gas after December 31, 2021. The federal government announced its intention in December 2020 to raise the carbon tax in Canada to $170/tonne by 2030. This announcement confirmed that our decision to accelerate our off-coal strategy to the end of 2021 was prudent.

We saw significant progress in our renewables portfolio this year. In October, we announced that our 10 MW WindCharger battery storage project began commercial operation. This project had a total capital cost of approximately $14 million, with approximately 50 per cent being funded through the support of Emissions Reduction Alberta. It is located behind the fence at the Summerview wind facility and is a first-of-its-kind example of firm, truly green electricity. It is a test of a future where batteries back up renewable and intermittent renewable energy sources.

In December, we acquired a 49 per cent interest in the Skookumchuck wind facility in Washington State. We combined this interest with our Alberta Windrise wind project and our Ada cogeneration project to complete a dropdown of these three highly contracted assets to TransAlta Renewables. This transaction was a win/win for TransAlta and TransAlta Renewables shareholders. TransAlta Renewables shareholders received $439 million of assets from TransAlta and TransAlta continues to own a 60 per cent interest through our ownership in TransAlta Renewables. The transaction extended the contracted cash flow horizon at TransAlta Renewables and provides stability and sustainability to our $150-million annual dividend earned from our ownership in TransAlta Renewables. This transaction gave us the confidence to also concurrently announce a dividend increase of six per cent for our TransAlta shareholders.

In December, we announced a small investment in a company called EMG International LLC, which has a technology that biologically cleans wastewater in the food processing industry. We believe that water conservation will become a key pillar of sustainability and that working with EMG to both expand their business and also market clean and renewable energy to their customer base is a low-risk and low-cost way to expand our reach to US industrial customers for E^2SG offerings in cogeneration, wind, solar and now, water.

Overall, our Clean Energy Investment Plan is on track and is the right strategy for the trends ahead where customers are demanding clean, low-cost and reliable electricity. By the end of 2021, Keephills 2 and 3 will be running on gas, Sundance Unit 5 will be under construction and our coal mine will be shut down and transitioned to reclamation only. As the capital needs of our Clean Energy Investment Plan reach completion, more cash will be available to TransAlta

> **"TransAlta is incredibly well positioned to lower greenhouse gas emissions while continuing to provide low-cost, reliable electricity to our customers. Our strategy is simple and focused, our performance is consistent, and our people are exceptional."**

Adjusted Availability

$927 million

Comparable EBITDA

A $7 million increase over 2019 after adjustments shareholders for re-investment, share buyback and dividends. The $150 million of cash that TransAlta Renewables annually pays in dividends to TransAlta shareholders is a stable and consistent source of cash flow for investors that, when combined with excess cash from our Alberta business and our energy marketing team, gives us a strong base of cash flow for opportunities that are emerging in the broader energy transition.

Resilient People

For a business that prides itself on serving the community, a pandemic is a difficult challenge, but is in no way insurmountable. Our people quickly organized to protect those essential employees who had to continue to work from our facilities throughout the pandemic. By June, those who had been working from home were able to return to our offices with strong medically approved protocols for social distancing, masking and wiping all surfaces that we touched. It was disappointing to have to return to our home offices in December in Canada and the US, and 2021 will be another year of adapting to what comes with the pandemic. Yes as we have seen in 2020, the team has outstanding practices for running the company and will continue delivering on our strategy no matter what.

In 2020, we demonstrated that we are One TransAlta made up of many parts. We are truly stronger together. We achieved top-quartile results in our Organizational Health Index, a survey where our people assess TransAlta's performance and results are measured against three million other employees assessing the organizational health of their companies. It has taken us four years to move from fourth quartile to first, an achievement that could only be done thanks to the consistent commitment from leaders across the company.

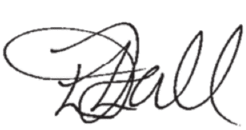
I am incredibly proud that we have adopted a Diversity, Equity and Inclusion Pledge that commits the company to advance diversity and inclusion in the workplace. By undertaking this pledge, we will seek to remove systemic barriers that may prevent diverse employees from thriving, including visible minorities, Indigenous peoples, members of the LGBTQ+ community, persons with disabilities and women. For us, diversity and inclusion are about ensuring belonging for all our employees. In 2021, our plans and results will be reported to the Board of Directors.

Looking Forward

As the team looks ahead, they see a number of opportunities to expand our gas and renewables fleet in Canada, the US and Australia. While we are not the only organization pursuing such projects, we find that customers highly value the skills and capabilities that companies who specialize in electricity bring to the table. TransAlta will continue to be a company focused on technology and innovation while exploring the viability of E^{2}SG investments in carbon capture and storage, hydrogen, pumped storage, batteries and the like. The team has over 3,000 MW in its growth portfolio, including the innovative Brazeau hydro pumped storage facility. As governments and companies align to the idea of net zero by 2050, projects like Brazeau that can store a reliable source of green energy become that much more valuable. TransAlta is poised to accelerate and deliver new EBITDA growth in 2021 and beyond.

We also expect increasing investor and stakeholder pressure to continue to reduce our emissions and green our fleet. TransAlta is incredibly well positioned to lower greenhouse gas emissions while continuing to provide low-cost, reliable electricity to our customers. Our strategy is simple and focused, our performance is consistent, and our people are exceptional.

As always, we thank you for your investment in the company and your support. I am especially grateful for our hard-working board who worked side-by-side with me over the last three years so that we could transition the leadership of TransAlta to a new CEO and a strong management team without missing a beat. Despite a worldwide pandemic and exceptional impacts to the Alberta economy, 2020 was a strong year for TransAlta. That's 100 per cent on the shoulders of our tough and resilient workforce who do their work without fanfare and by leading from every corner of the organization.



Dawn L. Farrell
President and Chief Executive Officer
March 2, 2021

Message from the Chair

I have had the great honour and privilege to serve as the Chair of the Board of Directors of TransAlta Corporation for the past year. To say that the last year has been eventful for TransAlta would be a tremendous understatement. The COVID-19 pandemic has disrupted every sector of the Canadian economy, resulting in significant energy demand destruction, including in the electricity sector.

As a result of the talent and preparedness within the organization, the teams at TransAlta ensured that we weathered this unforeseen storm with strength and pivoted where required with precision. It was, of course, the biggest obstacle we had to overcome in 2020. The pandemic accelerated at a time when we had just commenced a major construction project that required significant effort to maintain a safe and healthy work environment. As an essential service, it was imperative that we secure our normal course supply chain as well as acquire substantial personal protective equipment for which there was a worldwide shortage. Through it all, the project was completed on time and on budget and the TransAlta team was able to keep all operations running efficiently to ensure there were no supply disruptions to our customers. More importantly, the COVID-19 virus barely found its way into our numerous workspaces and the protocols put in place were robust enough to prevent any on-site transmission within our workforce.

In difficult times such as those we all experienced in 2020, organizations get tested in ways no one could have foreseen. I am incredibly proud of the way the Board and management worked together to manage the pandemic response. Like all others, we had to adapt to remote meetings that challenged our collective abilities to remain efficient and productive. Responding to the pandemic imposed significant additional time requirements on all members of the leadership team and the Board beyond those required to execute the business plan. I am incredibly proud of every member of the TransAlta organization for their effort, adaptability, innovation and focus, which allowed us to achieve virtually all of the corporation's key objectives for the year, albeit in a manner materially different than anticipated when those targets were set. Never has the talent within the organization been tested in the way it was in 2020 and I can't overstate the exemplary performance of the entire team.

I believe management's response to the pandemic was best in class. Throughout the year and into 2021 as information regarding the health threats of the virus evolved, keeping all members of the TransAlta team factually informed was a top priority. This was clearly a challenge with lots of conflicting information circulating in the news and social media. Our answer was to retain the services of doctors, immunologists and, more recently, a vaccinologist, to communicate directly with all members of the organization through frequent Town Halls during which the experts answered questions posed by our staff. I believe this direct access to health care professionals allowed everyone to make informed decisions about how to respond to the pandemic in the context of their own personal and family situations. As a result, the incidence of the virus within our workforce was minimal with, to the best of our knowledge, no transmission on any TransAlta work site. This also allowed us to confidently and safely re-open our head office with the majority of our staff returning on a full- or part-time basis sooner than most other businesses. I believe that was a key factor in us achieving the strong financial results we delivered to our shareholders.

Pandemic Response

An exemplary response to the pandemic was not our only notable achievement in 2020. We are proud to be the recipients of two important recognitions of the efforts of our leadership team and the Board of Directors — the Governance Gavel Award from the Canadian Coalition for Good Governance, and our significant jump in rank on *The Globe and Mail's* Board Games ranking. These are important achievements to continue to establish the company as an industry leader in corporate governance and disclosure. The importance of diversity both in the organization and on the Board is well understood within TransAlta and we are steadfast in our commitment to the goals that we have set surrounding diversity and inclusion within the organization. While we already have significant diversity within the organization, more work remains to be done and we are committed to undertaking that work. However, diversity for the sake of diversity doesn't benefit anyone — diversity that develops and promotes talent within the organization is our objective. We are confident we can achieve our aggressive diversity targets within the time frames set out by our leadership team. Of particular note, in response to an employee initiative, during 2020 we created a Diversity and Inclusion Council within TransAlta with representation from many levels within the organization to advance and enhance our diversity initiatives.

As always, the safety of our people remains a top priority. Safely completing our first coal to gas conversion in Alberta was another major accomplishment. This conversion is the first big step in our commitment to cease all coal mining operations by the end of 2021 and cease using coal in our Canadian fleet by the end of 2023. We are on track to deliver on the Clean Energy Investment Plan announced in 2019. Unfortunately, this transition means that we will part ways with a significant number of long-term employees in our thermal fleet. We thank all those employees for their outstanding commitment and dedicated efforts over many years in support of the corporation.

Year-end 2020 marked the end of a capacity market in Alberta. Our team has worked hard to prepare the organization for the Alberta merchant market in which we now operate. We are confident those preparations will result in a seamless transition supporting continued strong financial performance. Another milestone achieved in 2020 was receipt of the final $400-million tranche of capital associated with the 2019 transaction with an affiliate of Brookfield Asset Management. The resulting strengthening of our balance sheet allows us to now direct our free cash flow towards moving our growth strategy forward and returning more capital to shareholders through increased dividends. Another key achievement for 2020 was bringing WindCharger, Alberta's first utility-scale battery storage project, online. We are all tremendously excited about projects like this and the new opportunities we are now pursuing to deliver on our commitment to transition TransAlta into a leading clean electricity company.

In early February, the Board of Directors announced Dawn Farrell's retirement and the appointment of John Kousinioris as incoming CEO effective April 1, 2021. Dawn's 35-year career in electricity is full of significant accomplishments, including ushering TransAlta into its clean electricity future and its departure from coal-fired generation — Dawn will be truly missed. Join me in congratulating John on this new appointment. He is poised to take the company into what will be an exciting time as clean electricity becomes an even more central and essential actor in the energy that is needed to fuel our lives. I have every confidence in John's ability to lead the company.

Our organization is strong, talented, agile and demonstrably capable of effectively responding to disruptive events that challenge lesser organizations. In 2020, we lost the talent and leadership of our Chairman Ambassador Gordon Giffin who retired at the Annual General Meeting. We have all benefited greatly from his leadership and are immensely grateful for his contributions to TransAlta. Sincerest thanks are also extended to all of our stakeholders, employees, Board members and communities in which we operate for collaborating to overcome the many different challenges we have faced. On behalf of your Board, I can assure you that TransAlta remains dedicated to responsible growth and energy project development and is on the right strategic path to deliver the clean electricity needs of the future.

John P. Dielwart
Chair of the Board of Directors
March 2, 2021

$9.5 billion
Enterprise Value
Strong balance sheet and capital discipline

$3.0 billion
Market Capitalization
Listed on the TSX and the NYSE

Engaged Workforce
Our Employees are Central to Value Creation
Approximately 1,500 active employees

>109 years
Generation Experience
The foundation for our focused strategy

Diversified Portfolio
75 Generating Facilities with Approximately 8,000 MW of Net Capacity
Operating in Canada, the United States and Australia

Hydro | Solar | Wind | Storage | Gas | Coal

One of Canada's Largest Publicly Traded Power Generators

We own, operate and manage a highly contracted and geographically diversified portfolio of assets

A Focused Strategy for Value Creation

Our goal is to deliver shareholder value by delivering solid returns through a combination of dividend yield and disciplined growth in cash flow per share

Successfully Executing Our Conversion to Gas

We will be off coal in Canada by the end of 2021 with a fully-funded transition plan

Delivering Growth in Our Renewables Fleet

We have a robust development portfolio with >2.4 GW of renewable energy opportunities and are the sponsor and majority owner of TransAlta Renewables

$358 million

Free Cash Flow in 2020

Strong performance despite COVID-19 challenges

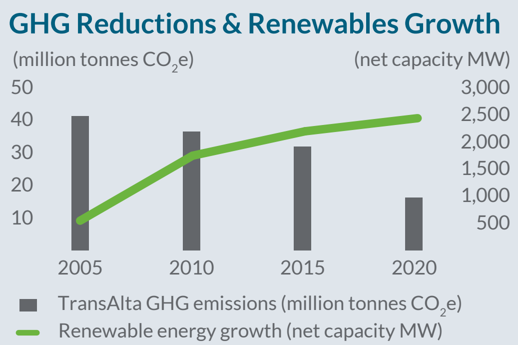
25 million tonnes

Reduction in Greenhouse Gas Emissions Since 2005

Better than any country in the world on a % basis

1,500 MW

Net Capacity Growth in Renewable Energy Since 2005



$15 million

Community Investment Over the Last Six Years

Youth & Education, Environmental Leadership

Community Health & Wellness

Alberta's First

Battery Storage Project

Commissioned in 2020 and 50% funded through Emissions Reduction Alberta

The Largest Producer of Wind Power in Canada and Hydro Power in Alberta

Contributed more than 10 per cent of Canada's Required GHG Emissions Reductions
as per Canada's 2030 GHG target under the Paris Agreement

Adopted Diversity, Equity & Inclusion Pledge
Signed by the Board and Executive team, supporting our gender diversity goal of 40 per cent female employment by 2030

Progressed Our Safety Culture Transformation
The safety of our people, communities and the environment is one of our core values

One TransAlta Comprising Many Parts
Achieved top quartile results on the Organizational Health Index

Our E²SG Reporting and Recognition

Economic / Environment / Social / Governance

We have reported on sustainability for over 25 years, and 2020 marked our sixth year of integrating financial and environment, social and governance ("ESG") disclosure. We track over 80 social and environmental key performance indicators and report in alignment with TCFD[1] and SASB[2], two leading ESG frameworks.

Our leading sustainability target process links targets to sustainability and financial materiality, sets macro targets that are both year-over-year and long term, and involves Executive and Board approval.

TransAlta's Five Sustainability Pillars

Clean, Reliable and Sustainable Electricity Production
Safe, Healthy, Diverse, and Engaged Workplace
Positive Indigenous, Stakeholder and Customer Relationships
Progressive Environmental Stewardship
Technology and Innovation

We have membership in and participate with key sustainability organizations and working groups such as the **EXCEL Partnership**, the **Canadian Business for Social Responsibility**, the **Energy Sector Sustainability Leadership Initiative**, **Canadian Electricity Association Sustainable Electricity Steering Committee** and **Future-Fit**, which all provide validation and support of our sustainability strategy.

CDP (the global disclosure system for environmental impacts formerly known as Carbon Disclosure Project) recognized TransAlta with an A- score, ranking the Company among industry leaders on climate change management. CDP has created a system that results in unparalleled engagement on environmental issues worldwide.

In 2021, TransAlta was once again added to the **Bloomberg Gender-Equality Index**. Standardized disclosure of gender-related data allows companies to attract capital and talent, empowers investors to make investment decisions through a social lens and enables employees and communities to hold companies accountable for progress.

The Globe and Mail reported that we moved from a ranking of 48 to a ranking of 14 in their **Board Games** report. Board Games assesses the work of Canada's largest Boards against a rigorous set of governance criteria (well beyond the minimum set by regulators), covering board composition, compensation, shareholder rights and disclosure.

(1) Task Force on Climate-Related Financial Disclosure (2) Sustainability Accounting Standards Board

A quarter century of energy transformation at TransAlta includes a complete shift away from coal, significant growth in renewable energy and growth in on-site gas solutions for customers. Transformation and E^{2}SG is a long-term commitment.

Our Progress from 2000 to 2025

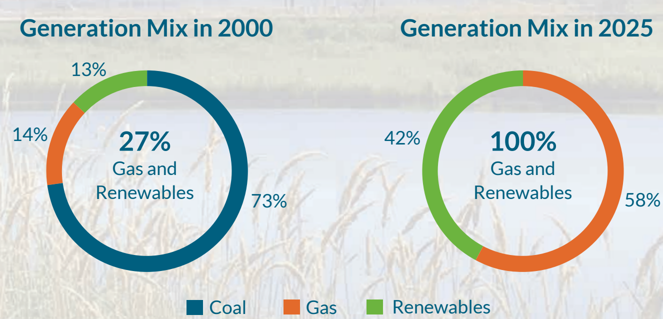
Coal transition: 17 coal facilities transitioned off coal, totalling approximately 5,000 MW (net capacity)

GHG emission reductions: On track for approximately 30 million tonnes CO_2e in reductions

Wind net capacity growth: >1,500 MW

Cogeneration growth: >1,000 MW

Transitioning to 100% Clean Electricity



Our Vision

This defines what our company aspires to be and is working toward — it is our why.

A leader in clean electricity — committed to a sustainable future

Our Mission

This defines our core purpose — it is how we do it.

Provide safe, low-cost and reliable clean electricity

Our Values

These principles define our corporate culture. They reflect our skills and mindset, while providing a framework for everything we do.

Safety
Ensure the health and safety of our people, partners and stakeholders

Innovation
Develop and embrace innovative solutions to challenges

Sustainability
Reduce the impact of resource use in everything we do

Respect
Support our people, our partners, our communities and our environment

Integrity
Focus on honesty, transparency and doing what's right

Management's Discussion and Analysis

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our 2020 audited annual consolidated financial statements (the "consolidated financial statements") and our 2020 annual information form ("AIF"), each for the fiscal year ended Dec. 31, 2020. 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, 2020. 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 March 2, 2021. 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.*

Business Model

Our Business

We are one of Canada's largest publicly traded power generators with over 109 years of operating experience. We own, operate and manage a highly contracted and geographically diversified portfolio of assets representing 8,128 megawatts ("MW")[(1)] of capacity and use a broad range of fuels that include water, wind and solar, natural gas, and thermal coal. The Corporation is currently undertaking a multi-year transition to convert or retire all of our thermal coal units completely by the end of 2025. This transition will see our thermal units in Alberta discontinue all firing with thermal coal and the discontinuation of all coal mining operations by the end of Dec. 31, 2021. Our Centralia coal-fired facility in Washington State is committed to be retired under the TransAlta Energy Transition Bill. Consistent with our commitment under this bill, Centralia Unit 1 retired on Dec. 31, 2020, and the remaining unit is set to retire on Dec. 31, 2025. 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 and we are committed to a sustainable future. Our mission is to provide safe, low-cost and reliable clean electricity. With our 109-year history of powering economies and communities, 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, all of which enable us to work towards our common goals. These values are the principles that define our corporate culture. They reflect our skills and mindset, while providing a framework for everything we do, guiding both internal conduct and external relationships. 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 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. We refer to this as E^2SG. This MD&A integrates our financial or economics ("E") 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 E^2SG affects our business, we have referenced the provincial securities commission guidance, Global Reporting Initiative, 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 Indicators ("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 the 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.

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 US securities laws, including the US *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 eliminate coal as a fuel source in the Alberta thermal fleet by 2021; our 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 2021 and beyond, including potential for growth in renewables and on-site and cogeneration assets, including the demand therefor and greenfield development acquisitions; the amount of capital allocated to new growth or development projects and the funding thereof; our business, anticipated future financial performance and anticipated results, including our outlook and performance targets; our expectation that the sale of TransAlta's interest in the Pioneer Pipeline will close in 2021; receiving funding under the Canada Emergency Wage Subsidy program; the ability to reach a commercial solution with Energy Transfer Canada regarding the construction and operation of the Kaybob 3 cogeneration facility; 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 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 to the benefits of the conversions and repowering; the terms of the current or any further proposed share buyback 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; our ability to achieve our E^2SG 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, the Australian 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: the impacts arising from COVID-19 not becoming significantly more onerous on the Corporation, which includes the Corporation being permitted to continue to operate as an essential service; 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 investment and credit markets; Alberta spot power prices being in the range of $58 to $68 per megawatt hour ("MWh") in 2021; Mid-C spot power prices being in the range of US$25 to US$35 per MWh in 2021; sustaining capital in 2021 being between $175 million and $210 million; productivity capital of $3 million to $7 million; applicable 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 Alberta thermal 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 conversion to gas, growing TransAlta Renewables and realizing the full economic benefit from our capacity, energy and ancillary services.

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 the impact of COVID-19, which cannot currently be predicted, and which present risks including, but not limited to: more restrictive directives of government and public health authorities; reduced labour availability and ability to continue to staff our operations and facilities; disruptions to our supply chains, including our ability to secure necessary equipment or to obtain regulatory approvals on the expected timelines or at all; COVID-19-related force majeure claims; restricted access to capital and increased borrowing costs; a further decrease in short-term and/or long-term electricity demand and lower merchant pricing in Alberta and Mid-C; reductions in production; increased costs resulting from our efforts to mitigate the impact of COVID-19; deterioration of worldwide credit and financial markets; a higher rate of losses on our accounts receivable due to credit defaults; impairments and/or writedowns of assets; and adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats. The forward-looking statements are also subject to other risk factors that include, but are not limited 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 man-made disasters, including those resulting in dam or dyke failures; the threat of domestic terrorism and cyberattacks; pandemics 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, 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 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; 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, 2020.

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. The purpose of the financial outlooks contained herein is to give the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. 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.

Corporate Strategy

Our strategic focus is to invest in a disciplined manner in a range of clean and renewable power generation such as hydro, wind, solar, energy storage and thermal (natural gas-fired and cogeneration) and develop customer-centric green power solutions that produce electricity for the needs of our industrial customers and communities in order to deliver returns to our shareholders.

Clean Energy Investment Plan

TransAlta's Clean Energy Investment Plan, announced in 2019, includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in on-site generation and renewable electricity. The Clean Energy Investment Plan identified opportunities of $1.9 billion to $2.1 billion that TransAlta is pursuing. A significant number of these opportunities have been completed, with the projects achieving commissioned status in 2019 and 2020.

The implementation and execution of TransAlta's Clean Energy Investment Plan, including the acceleration of certain features of that plan, is being facilitated by the $750 million strategic investment (the "Brookfield Investment") by Brookfield Renewable Partners or its affiliates (collectively, "Brookfield") that we announced in March 2019. The first $350 million tranche of Brookfield's Investment closed in May 2019 and facilitated the acceleration of our conversion to gas plan discussed below. The second $400 million tranche of Brookfield's Investment closed on Oct. 30, 2020, and will help further the advancement and implementation of the remainder of our Clean Energy Investment Plan. The Brookfield Investment will fund other growth initiatives, while helping the Corporation maintain a strong balance sheet and financial flexibility to carry out the other pillars of our strategy discussed below. Please refer to the Significant and Subsequent Events section of this MD&A for further details.

Please refer to the 2021+ Sustainable Development Targets section of this MD&A for further details on sustainability targets and near-term objectives that further support our Clean Energy Investment Plan.

Our strategic priorities were advanced in 2020 and what follows is an update of how we executed in 2020, as well as our intentions for 2021 and beyond:

1. Successfully convert to natural gas as the primary fuel source in the Alberta thermal fleet

We are transitioning our Alberta thermal fleet to natural gas as part of our Clean Energy Investment Plan. We plan to invest between $900 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 while delivering attractive returns through leveraging the Corporation's existing infrastructure.

The highlights of these gas conversion investments include:

- Positioning TransAlta's fleet as a low-cost clean energy 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:

- ***Conversion to gas*** – TransAlta's Clean Energy Investment Plan includes converting three of our existing Alberta thermal units to gas during 2021 by replacing existing coal burners with natural gas burners. The cost to convert each of TransAlta's wholly owned units is expected to be approximately $35 million per unit. On Feb. 1, 2021, we announced the completion of the conversion to gas of Sundance Unit 6. The Corporation continues to advance conversion of its Keephills Unit 2 and Keephills Unit 3 for completion later in 2021 and has issued Full Notice to Proceed ("FNTP") for both units. In addition, on April. 4, 2020, the dual-fuel conversion of Sheerness Unit 2 was completed. The Sheerness Unit 1 conversion to gas is in progress with expected completion in the first quarter of 2021. The Sheerness facility will receive it's last coal shipment in the first quarter of 2021, with coal stock being actively depleted until the end of 2021. The elimination of coal as a fuel source will reduce future fuel costs and greenhouse gas ("GHG") costs at Sheerness.

- ***Gas Repowering*** – The Clean Energy Investment Plan also includes the repowering of the steam turbines at Sundance Unit 5 and, potentially, Keephills Unit 1, by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. The repowered units are expected to be a 35 per cent to 45 per cent lower capital investment when compared to a new combined-cycle facility, while achieving a similar heat rate. During the first quarter of 2020, we received regulatory approval from the Alberta Utilities Commission ("AUC") and Alberta Environment and Parks for the repowering of

Sundance Unit 5 and Keephills Unit 1 into combined-cycle units. During the fourth quarter of 2020, an equipment supply agreement was executed as part of the strategy to repower Sundance Unit 5 into a highly efficient combined-cycle unit. The commercial operation date is anticipated in the fourth quarter of 2023. The Sundance Unit 5 repowered combined-cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $800 million to $825 million, well below a greenfield combined-cycle project. As part of this transaction, we also acquired a long-term power purchase agreement ("PPA") for capacity plus energy, including the pass-through of GHG costs, starting in late 2023 with Shell Energy North America (Canada). The Corporation will continue to evaluate the prospect for the repowering of Keephills Unit 1 in 2021 and 2022 as a supply addition to the Alberta market in the 2026 to 2030 time frame.

- ***Cessation of Coal-Fired Operations by 2022*** – TransAlta has determined to cease coal-fired operations in Canada by Jan. 1, 2022. During the third quarter of 2020, we approved the accelerated shutdown of the Highvale mine by the end of 2021, and the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. We will continue to actively deplete our coal stock and will wind down our mining activity by the end of 2021. As a result, we announced that Keephills Unit 1 and Sundance Unit 4 will discontinue firing with coal and will be subject to further strategic assessment as to their feasibility to operate on gas effective Jan. 1, 2022. The maximum capability of these units will be reduced to 70 MW and 113 MW, respectively, when transitioned to operate on gas.

- ***Pioneer Pipeline and Gas Supply*** – On Oct 1, 2020, TransAlta announced that it had entered into a definitive Purchase and Sale Agreement for the sale of its 50 per cent interest in the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") (the "Transaction"). The purchase price of $255 million represents both TransAlta's and Tidewater Midstream & Infrastructure Ltd.'s ("TMI") interests. This agreement replaces the previous Purchase and Sale Agreement to sell the Pioneer Pipeline to NOVA Gas Transmission Ltd. ("NGTL") from the second quarter of 2020. ATCO acquired the right to purchase the Pioneer Pipeline through an option agreement with NGTL. Following closing of the Transaction, the Pioneer Pipeline will be integrated into NGTL's and ATCO's Alberta integrated natural gas transmission systems to provide reliable natural gas supply to TransAlta's Sundance and Keephills power-generating stations. As part of the agreement, TransAlta has entered into incremental, long-term firm natural gas delivery transportation agreements with NGTL for 351 TJ per day, bringing the total firm natural gas transportation contracts up to 400 TJ per day by 2023. TransAlta's current commitments, including the 139 TJ per day supply arrangement with TMI, will remain in place until the closing of the Transaction. The Transaction is subject to customary regulatory approvals and is anticipated to close during the second quarter of 2021.

- ***Retirement of Sundance 3*** – On July 22, 2020, the Corporation announced that it gave notice to the Alberta Electric System Operator ("AESO") to retire the mothballed coal-fired Sundance Unit 3 effective July 31, 2020. The retirement decision was largely driven by our assessment of future market conditions, the age and condition of the unit, and our ability to supply energy and capacity from our generation portfolio in Alberta. This decision advances our transition to 100 per cent clean electricity by 2025.

2. Deliver growth in our renewables fleet

We expanded our renewables platform in the US in 2020 and continue to identify additional opportunities with customers on electricity offerings with a higher component of power coming from renewable sources. Our focus is to deliver solid returns using exceptional project development, construction and integration of skills and capabilities. In 2019, the Big Level and Antrim wind development projects were commissioned, allowing us to invest $340 million in projects with solid returns. The Skookumchuck wind project and WindCharger battery storage project were commissioned in 2020, representing investments of $93 million, which were within expected cost estimates. For 2021, we are constructing the Windrise wind project in Alberta, which is expected to be commissioned by year-end. Our contract expansion at the Southern Cross facility in Australia provides an additional opportunity to invest in renewables.

The following provides more detail on our 2020 achievements:

Windrise Wind Project

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project ("Windrise") was identified by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO subsequently executed a Renewable Electricity Support Agreement with a 20-year term. Windrise 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. Windrise has secured approval for the wind facility and transmission line required to connect the facility to the Alberta grid from the Alberta Utilities Commission ("AUC"). Construction activities on Windrise continue to advance with all appropriate procedures in place to protect the construction team during the COVID-19 pandemic. However, as a result of COVID-19 and related delays in construction, the commercial operation date is expected to occur during the second half of 2021. As of Dec. 31, 2020, Windrise was 78 per cent complete.

Skookumchuck Wind Project
On Nov. 25, 2020, TransAlta completed the acquisition of the 49 per cent equity investment in the Skookumchuck wind project ("Skookumchuck") with Southern Power Company, a subsidiary of Southern Company. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas V136 wind turbines. The project began commercial operation on Nov. 7, 2020, and has a 20-year PPA with Puget Sound Energy. TransAlta's total net capital investment was $86 million (US$66 million) cash, with an additional $77 million (US$59 million) being funded with tax equity financing.

BHP Nickel West Contract Extension
On Oct. 22, 2020, Southern Cross Energy ("SCE"), a subsidiary of the Corporation, replaced and extended its current PPA with BHP Billiton Nickel West Pty Ltd. ("BHP"). SCE is composed of four generation facilities with a combined capacity of 245 MW in the Goldfields region of Western Australia.

The new agreement was effective Dec. 1, 2020, and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038, and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross facilities for BHP's mining operations located in the Goldfields region of Western Australia. The extension will provide SCE a return on new capital investments, which will be required to support BHP's future power requirements and recently announced emission reduction targets. The amendments within the PPA also provide BHP participation rights in integrating renewable electricity generation, including solar and wind, with energy storage technologies, subject to the satisfaction of certain conditions. Evaluation of renewable energy supply and carbon emissions reduction initiatives under the extended PPA with SCE are underway, including an 18.5 MW solar photovoltaic facility supported by a battery energy storage system and a waste heat steam turbine system.

WindCharger Project
On Aug. 1, 2020, the WindCharger battery storage project ("WindCharger") was sold to TransAlta Renewables. WindCharger has been operational since Oct. 15, 2020, and is the first utility-scale battery energy storage project in Alberta. The WindCharger project has a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. It is located in southern Alberta in the Municipal District of Pincher Creek next to TransAlta's existing Summerview wind facility substation. WindCharger stores energy produced by the nearby Summerview II wind facility and discharges it into the Alberta electricity grid at times of peak demand. TransAlta is expected to receive co-funding of almost 50 per cent of the $14 million construction cost from Emissions Reduction Alberta. WindCharger is participating in both the Alberta wholesale energy and ancillary services market of the AESO.

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 March 1, 2018, consists of a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corporation. The Antrim wind project ("Antrim") acquired on March 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.

3. Expand presence in the US renewables market

A major focus of our business development efforts is on the renewables segment of the US market. Demand for new renewables in the US is expected to continue its strong growth in the near term and President Biden is expected to initiate policies designed to support further renewables growth. We have started prospecting for new renewable development sites in a number of attractive US markets. 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, the Skookumchuck wind project and the prospecting activities discussed above, TransAlta acquired a portfolio of up to 1,250 gigawatts ("GW") of wind development projects in the US in 2019. A number of projects acquired within this portfolio are currently in the early stages of development by TransAlta.

4. Advance and expand our on-site generation and cogeneration business

We are focused on growing our on-site and cogeneration asset base, a business segment we have deep experience in, having provided on-site cogeneration services to customers since the early 1990s. Our current pipeline under evaluation is approximately 600 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 the costs of power production, replace aging or inefficient equipment, reduce network costs and meet their ESG objectives.

On Nov. 30, 2020, TransAlta acquired a 30 per cent equity interest in EMG International, LLC ("EMG") to diversify our sustainability offerings to customers while directly supporting our clean energy transition and sustainability goals. Included in the purchase price of US$12 million is an estimated component contingent on EMG realizing certain earnings metrics in 2020 and 2021, following the acquisition. The final contingent amount will be calculated based on actual earnings metrics achieved. EMG is an established company with over 25 years of experience in process wastewater treatment and specializes in the design and construction of high-rate anaerobic digester systems. EMG's wastewater treatment process converts organic waste into a valuable source of renewable energy. Their technology produces a biogas stream that can be used as fuel to generate electricity, displacing energy consumed from higher-emitting resources. The investment provides a unique opportunity for TransAlta to leverage its vast expertise in on-site generation to support further advancements by EMG in the waste-to-energy space. This investment will advance the Corporation's presence in the US sustainability and on-site generation markets.

On May 19, 2020, the Corporation closed the acquisition of a contracted natural-gas-fired cogeneration asset from two private companies for a purchase price of US$27 million. The Ada facility is a 29 MW cogeneration facility ("Ada") in Michigan that is contracted under a PPA and a steam sale agreement for approximately six years with Consumers Energy and Amway.

In 2019, TransAlta and Energy Transfer Canada ("ET Canada" formerly known as SemCAMS Midstream ULC) entered into agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant ("K3"). The facility was expected to receive its final regulatory approvals in the second half of the year and begin construction in December 2020. On Sept. 25, 2020, the AUC released a decision in which it approved the construction and operation of the facility, but denied the application for the Industrial System Designation. We are in ongoing commercial and technical discussions with ET Canada relative to the project at K3, or potentially developing a new project at another site owned and/or operated by ET Canada

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 $2.1 billion in liquidity, including $703 million in cash. During 2020, we closed an AU$800 million offering ("TEC Offering"), through TEC Hedland Pty Ltd. ("TEC"), a subsidiary of the Corporation, and received $400 million of the second and final tranche of the $750 million strategic financing from Brookfield. We repaid a $400 million medium-term note due on Nov. 25, 2020. Further to the final closings of the recently announced dropdown transaction to TransAlta Renewables, the Corporation has reached its target balance of $1.2 billion of senior corporate debt. In 2019, we received the first tranche of the Brookfield Investment for $350 million, increased our credit facilities by $200 million to a total of $2.2 billion while extending the maturity of the term by one year, and successfully obtained US$126 million of tax equity financing associated with the US Wind Projects.

The Clean Energy Investment Plan is being funded from the cash raised through the Brookfield Investment, cash generated from operations and capital raised through TransAlta Renewables. For further details on the Brookfield Investment and TEC Offering, please refer to the Significant and Subsequent Events section of this MD&A.

Management of the Alberta Portfolio

On Dec. 31, 2020, the power purchase arrangement for many of our Alberta hydro facilities and Keephills 1 and 2 units expired and, effective Jan. 1, 2021, these facilities began operating on a merchant basis in the Alberta market. The facilities are dispatched to benefit from the price volatility in the Alberta energy-only electricity market and to provide ancillary services. As such, they are to be part of our Alberta electricity portfolio optimization activities. The variability in production by facility is driven by the diversity in our fuel types, which enables portfolio management. The Alberta portfolio of production includes hydro, wind, energy storage and thermal units. A portion of the baseload of the portfolio is hedged to provide cash flow certainty.

Growth and Conversion to Gas 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 status of the significant growth and major projects in the Clean Energy Investment Plan is outlined below:

	Total project				
Project	Estimated spend	Spent to date[(1)]	Estimated spend in 2021	Target completion date[(2)]	Details
Big Level wind development project[(3)]	225 - 240	234	1	Commissioned in 2019	90 MW wind project with a 15-year PPA
Antrim wind development project[(4)]	100 - 110	106	1	Commissioned in 2019	29 MW wind project with two 20-year PPAs
Pioneer gas pipeline partnership	95 - 100	105	—	Commissioned in 2019	50 per cent ownership in the 120 km natural gas pipeline to supply gas to Sundance and Keephills
Skookumchuck wind development project[(5,6)]	160 - 170	86	—	Commissioned in 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[(6)]	270 - 285	205	68	H2 2021	207 MW wind project with a 20-year Renewable Electricity Support Agreement with AESO
WindCharger battery[(7)]	7 - 8	7	—	Commissioned in 2020	10 MW/ 20 MWh utility-scale Battery Storage Project
Boiler conversions	120 - 200	75	40	2020 to 2021	Conversion to gas at Alberta Thermal
Repowering	800 - 825	113	298	Q4 2023	Repower Sundance Unit 5 to a combined cycle design
Kaybob cogeneration project	105 - 115	48	40	TBD[(8)]	40 MW cogeneration project with ET Canada
Total	**1,882 - 2,053**	**979**	**448**		

(1) Represents cumulative amounts spent as of Dec. 31, 2020.
(2) H1 is defined as the first half of the year and H2 is defined as the second half of the year.
(3) The numbers reflected above are in Canadian dollars, but the actual cash spend on this project is in US dollars 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 2021 is US$1 million. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(4) The numbers reflected above are in Canadian dollars, but the actual cash spend on this project is in US dollars 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 2021 is US$1 million. TransAlta Renewables funded a portion of the construction costs using its existing liquidity and the remaining was funded with tax equity financing.
(5) The numbers reflected above are in Canadian dollars, but the actual cash spent on this project is in US dollars. The total cash spent was US$66 million, with the remainder funded through tax equity financing of $77 million (US$59 million).
(6) The economic interest in Skookumchuck will be sold to TransAlta Renewables in the first half of 2021. The Windrise wind development project was sold to TransAlta Renewables on Feb. 26, 2021.
(7) The WindCharger project was acquired by TransAlta Renewables in 2020. Amounts shown are net of expected government reimbursements.
(8) Timing of the Kaybob cogeneration project is to be determined subject to ongoing commercial and technical discussions with ET Canada, as described above.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2020	2019	2018
Adjusted availability (%)	**90.3**	90	91.3
Production (GWh)	**24,980**	29,071	28,409
Revenues	**2,101**	2,347	2,249
Fuel, carbon compliance and purchased power	**968**	1,086	1,100
Operations, maintenance and administration	**472**	475	515
Net earnings (loss) attributable to common shareholders(1)	**(336)**	52	(248)
Cash flow from operating activities	**702**	849	820
Comparable EBITDA(1,2)	**927**	984	1,161
Funds from operations(1,2)	**685**	757	927
Free cash flow(1,2)	**358**	435	524
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(1.22)**	0.18	(0.86)
Funds from operations per share(1,2)	**2.49**	2.67	3.23
Free cash flow per share(1,2)	**1.30**	1.54	1.83
Dividends declared per common share	**0.22**	0.12	0.20
Dividends declared per preferred share(3)	**1.27**	0.78	1.29

As at Dec. 31	2020	2019	2018
Total assets	**9,747**	9,508	9,428
Total consolidated net debt(2,4)	**3,175**	3,110	3,141
Total long-term liabilities(5)	**5,376**	4,329	4,414

(1) 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.
(2) 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. Please 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.
(3) 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.
(4) Total consolidated net debt includes long-term debt, including current portion, amounts due under credit facilities, exchangeable securities, US tax equity financing and lease liabilities, net of available cash and cash equivalents, the principal portion of restricted cash on our subsidiary TransAlta OCP LP ("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.
(5) Certain comparative figures have been reclassified to conform to the current period's presentation. These reclassifications did not impact previously reported net earnings.

We showed strong performance and results within the current year, advancing our Clean Energy Investment Plan by accelerating our conversion to gas strategy, successfully managing our business during a global pandemic and keeping our people healthy and safe. We achieved these objectives despite the unfavourable impacts of COVID-19, including reduced electricity demand load, delays in construction and additional costs associated with new safety protocols and protective equipment required to effectively and safely operate our business. In spite of these challenges, we delivered strong operational performance and financial results in line with our guidance for comparable EBITDA and free cash flow ("FCF").

FCF, one of the Corporation's key financial metrics, totalled $358 million in 2020, down $77 million compared to last year. FCF, excluding the PPA Termination Payment received in 2019, decreased by $21 million compared to 2019. The decline was driven primarily by lower segmented cash flows at the Alberta Thermal segment and higher sustaining capital expenditures, partially offset by strong cash flows for Centralia and lower distributions paid to subsidiaries' non-controlling interests. Segmented cash flows for 2020 are consistent with 2019. Lower power demand and production in our Alberta Thermal segment and the impact of the total return swap recognized in 2019 in the Corporate segment was offset by higher performance in our Centralia, Wind and Solar, North American Gas and Energy Marketing segments. Significant changes in segmented cash flows are highlighted in the Segmented Comparable Results section of this MD&A.

Adjusted availability for 2020 was 90.3 per cent compared to 90.0 per cent in 2019. Lower planned and unplanned outages and derates within the generation segments were offset by the planned outage at Alberta Thermal for the Sundance Unit 6 turnaround and conversion to gas outage.

Production for 2020 was 24,980 gigawatt hours ("GWh") compared to 29,071 GWh in 2019. Overall, the production decrease was primarily due to planned outages, curtailments at Alberta Thermal and increased dispatch optimization at Alberta Thermal and Centralia due to lower merchant pricing, which was partially offset by higher production from higher wind and hydro resources and a full year of production at the Big Level and Antrim facilities. There was reduced electricity demand in North America due to COVID-19, which also had a significant impact on production.

Revenues for 2020 decreased by $246 million compared to 2019, as we saw lower demand and power prices across North America. This was partially offset by a full year of production from the Big Level and Antrim facilities in the Wind and Solar segment and the acquisition of the Ada facility during the year in the North American Gas segment.

Fuel, carbon compliance and purchased power costs in 2020 decreased by $118 million compared to 2019. Fuel, carbon compliance and purchased power costs were impacted by lower production in the year, offset by higher coal costs at Alberta Thermal and by the additional costs of production of the Ada facility. Coal costs include a writedown of coal inventory and increased depreciation resulting from the decision to accelerate the closure of the Highvale mine. Our ability to co-fire with natural gas assisted in reducing fuel costs as co-firing allows us to produce fewer GHG emissions than 100 per cent coal combustion and lowers our GHG compliance costs.

Operations, maintenance and administration ("OM&A") expenses for 2020 decreased by $3 million compared to 2019. OM&A decreased due to tighter cost controls, reduced staffing in line with conversion to gas transition plans, lower production at Centralia and Alberta Thermal, lower labour costs across multiple segments and lower legal fees. This was partially offset by the impact of the total return swap recognized in 2019 of $15 million, additional operating costs from new facilities including Big Level, Antrim and Ada, and the renegotiation of the Fort Saskatchewan maintenance agreement. Excluding the impact of the total return swap and new facilities, OM&A decreased by $28 million.

Comparable EBITDA decreased by $57 million compared to 2019. After adjusting for the PPA Termination Payments for 2019 and the AESO line loss adjustment of $8 million, comparable EBITDA increased by $7 million compared to 2019. Comparable EBITDA increased as a result of the new facilities at the Wind and Solar segment, higher comparable EBITDA in Centralia and continued strong performance in the Energy Marketing segment. This was partially offset by lower production at Alberta Thermal as a result of lower merchant demand. Significant changes in segmented comparable EBITDA are highlighted in the Segmented Comparable Results within this MD&A.

Net loss attributable to common shareholders for 2020 was $336 million compared to earnings of $52 million in 2019. Net loss attributable to common shareholders has been impacted by higher interest expense associated with the TEC Offering and the second tranche of the Brookfield Investment, higher depreciation from acceleration of the conversion to gas, gains recognized on the Keephills 3 and Genesee 3 asset swap that occurred in 2019, the $56 million settlement on the Sundance B and C PPAs in 2019 and further impacts related to our decisions to accelerate our transition to gas, including:

- Higher depreciation as we accelerate the closure of the Highvale mine;
- Writedown of $37 million of coal inventory;
- Onerous provision of $29 million on the coal supply contract for Sheerness; and
- Impairment of $70 million associated with the retirement of Sundance 3.

Ability to Deliver Financial Results

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

Year ended Dec. 31		**2020**	2019	2018
Comparable EBITDA	Target(1)	**925-1,000**	875-975	1,000-1,050
	Actual	**927**	984	1,161
	Adjusted actual(2)	**927**	928	1,004
FCF	Target(1)	**325-375**	350-380	300-350
	Actual	**358**	435	524
	Adjusted actual(2)	**358**	379	367

(1) Represents our revised outlook. 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.
(2) 2019 and 2018 were adjusted for the PPA Termination Payments as these were not included in the targets.

Significant and Subsequent Events

TransAlta Renewables Acquisitions

On Dec. 23, 2020, the Corporation announced that it had entered into definitive agreements for the acquisition by TransAlta Renewables of its 100 per cent direct interest in the 207 MW Windrise wind project located in the Municipal District of Willow Creek, Alberta; a 49 per cent economic interest in the 137 MW Skookumchuck wind facility located across Thurston and Lewis counties in Washington State; and a 100 per cent economic interest in the 29 MW Ada cogeneration facility located in Ada, Michigan. TransAlta Renewables' acquisition of the Windrise wind project closed on Feb. 26, 2021, and the acquisition of the economic interests in the Ada facility and the Skookumchuck wind facility are expected to close in April 2021. The total acquisition value for the portfolio of assets is expected to be $439 million, which includes the remaining construction costs for the Windrise wind project. TransAlta Renewables will fund the acquisition and remaining construction costs with the proceeds from the TEC Hedland financing as further described below.

TEC Hedland Pty Ltd. Secures AU$800 Million Financing

On Oct. 22, 2020, TEC, a subsidiary of the Corporation, closed an AU$800 million senior secured note offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The TEC Offering bears interest at 4.07 per cent per annum, payable quarterly and maturing on June 30, 2042, with principal payments starting on March 31, 2022. The TEC Offering has a rating of BBB by Kroll Bond Rating Agency.

TransAlta Renewables has received $480 million (AU$515 million) of the proceeds from the TEC Offering through the redemption of certain intercompany structures. An additional AU$200 million has been loaned to TransAlta Renewables by TransAlta Energy (Australia) Pty Ltd., which is a subsidiary of TransAlta. The loan bears interest at 4.32 per cent and will be repaid by Oct. 23, 2022, or on demand. The remaining proceeds from the TEC Offering were set aside for required reserves and transaction costs.

TransAlta Renewables used a portion of the proceeds from the redemption and the intercompany loan to repay existing indebtedness on its credit facility and to acquire the asset and economic interests noted above.

COVID-19

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic. The outbreak of COVID-19 has resulted in governments worldwide enacting emergency measures to constrain the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods, self-isolation, physical and social distancing, and the closure of non-essential businesses, have caused significant disruption to businesses globally, which has resulted in an uncertain and challenging economic environment.

The Corporation continued to operate under its business continuity plan, which focused on ensuring that: (a) employees who could work remotely did so and (b) employees who operate and maintain our facilities, and who were not able to work remotely, were able to work safely and in a manner that ensured they remained healthy. During the second and third quarters of 2020, the Corporation successfully brought employees who were working remotely back to the office without compromising health and safety standards. In November 2020, as a result of rising COVID-19 case counts in the Province of Alberta and in light of office attendance restrictions eventually imposed by the Government of Alberta, staff at TransAlta's head office returned to remote work protocols. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available and in use. Further, TransAlta maintains travel bans aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to limit contact with other employees and contractors on-site.

While our results have been impacted by price and demand as a result of COVID-19, all of our facilities continue to remain fully operational and capable of meeting our customers' needs. The Corporation continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements. Electricity and steam supply continues to remain a critical service requirement to all of our customers and has been deemed an essential service in our jurisdictions.

During the second quarter of 2020, the Government of Canada passed the Canada Emergency Wage Subsidy as part of its COVID-19 Economic Response Plan. The program's intent is to support employment by providing expense relief to companies that experienced revenue declines in 2020. In January 2021, TransAlta applied for support under this program and expects to receive $8 million (pre-tax) for application periods in 2020. This represents a portion of the funding that the Corporation is eligible for and funds will be used to support a strategy to add incremental employment within the Corporation. The Corporation will recognize these wage subsidies as funds are received in 2021.

The Corporation continues to maintain a strong financial position due in part to its long-term contracts and hedged positions. At year-end, we had access to $2.1 billion in liquidity, including $703 million in cash and cash equivalents.

Strategic Investment by Brookfield

On March 22, 2019, the Corporation entered into an agreement (the "Investment Agreement") whereby Brookfield agreed to invest $750 million in the Corporation. The Brookfield 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 TransAlta's Clean Energy Investment Plan, including facilitating or accelerating several key pillars of our 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. 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.

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. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in consideration for redeemable, retractable first preferred shares. The proceeds from the first tranche were used to accelerate our conversion to gas program. The Corporation intends to use the proceeds from the second tranche of the financing to advance the Corporation's conversion to gas program, fund other growth initiatives and for general corporate purposes.

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 Brookfield Investment. As of Dec. 31, 2020, 15,068,900 common shares have been repurchased in 2020 and 2019 for $129 million under the normal course issuer bid ("NCIB") program.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent by May 1, 2021. As of Jan. 8, 2021, Brookfield, through its affiliates, held, owned or had control over an aggregate of 33,845,685 common shares, representing approximately 12.4 per cent of the issued and outstanding common shares, calculated on an undiluted basis. In connection with the Investment Agreement, Brookfield is entitled to nominate two directors for election to the Board.

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 collaborate in connection with the operation and maximization of 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 Consolidated Statements of Earnings (Loss).

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 Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter was adjourned due to the COVID-19 pandemic and is now scheduled to proceed to trial for three weeks starting April 19, 2021. Please refer to the Other Consolidated Analysis section of this MD&A for additional information on the Mangrove proceedings.

Centralia Unit 1 Retirement

The Corporation owns a two-unit 1,340 MW thermal coal-fired facility in Centralia, Washington, in relation to which we have entered into a number of multiple year medium- and short-term energy sales agreements. In 2011, Washington State passed the TransAlta Energy Transition Bill (chapter 180, Laws of 2011) (the "Bill'') allowing the Centralia thermal facility to comply with the state's GHG emissions performance standards by ceasing coal generation in one of its two boilers by the end of 2020, and the other by the end of 2025. The Bill removed restrictions that had previously been imposed on the facility limiting the duration of new contracts from the facility and limiting the technology that the facility would be required to implement for nitrogen oxide ("NO_x ") controls. Centralia Unit 1 was retired from service effective Dec. 31, 2020.

Accelerated Shutdown of the Highvale Mine

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and, accordingly, the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. As at Dec. 31, 2020, the carrying value of the Highvale mine, including property, plant and equipment ("PP&E"), right-of-use assets and intangible assets, was $373 million. As a result, our cost per tonne of coal will increase as the fixed coal costs will be spread over lower volumes. During the second half of 2020, the increased depreciation expense and our cost per tonne of coal exceeded the net realizable value of the coal inventory and a writedown of $37 million was recognized in fuel, carbon compliance and purchased power. As the Highvale mine moves into the reclamation phase, our anticipated coal consumption is expected to continue to decline, further increasing the cost of coal and future expected writedowns in fuel costs. In 2020, we started the year with 2.1 million tonnes of coal inventory, during which we mined an additional 2.3 million tonnes and consumed 3.5 million tonnes. We ended the year with approximately one million tonnes of coal inventory and we will continue to actively deplete our coal stock as we wind down our mining activity by the end of 2021.

Normal Course Issuer Bid

On May 26, 2020, 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 the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.02 per cent of its public float of common shares, as at May 25, 2020. 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 the Corporation is authorized to make purchases under the NCIB began on May 29, 2020 and ends on May 28, 2021, 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 228,157 common shares (being 25 per cent of the average daily trading volume on the TSX of 912,630 common shares for the six months ended April 30, 2020) 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, 2020, under the current and previous NCIB, the Corporation purchased and cancelled a total of 7,352,600 common shares at an average price of $8.33 per common share, for a total cost of $61 million.

Management Changes

On Feb. 4, 2021, we announced that that Dawn Farrell, President and Chief Executive Officer, will retire from the Corporation and the Board on March 31, 2021, after leading the Corporation for almost a decade. John Kousinioris, currently Chief Operating Officer and, until his resignation on Feb. 5, 2021, President of TransAlta Renewables, will succeed Ms. Farrell as President and Chief Executive Officer and will join the Board on April 1, 2021. Prior to his appointment as Chief Operating Officer of TransAlta, Mr. Kousinioris held the roles of 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, and commercial and energy marketing.

On Feb. 6, 2021, Todd Stack, the Executive Vice President, Finance and Chief Financial Officer of the Corporation, accepted the position of President of TransAlta Renewables. Mr. Stack was promoted to Chief Financial Officer of the Corporation on May 16, 2019. Prior to being appointed as Chief Financial Officer, Mr. Stack served as Managing Director and Corporate Controller of the Corporation, and 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, Corporate Controller, as well as a member of Corporate Development, and he played a prominent role in the growth and the initial public offering of TransAlta Renewables. Prior to joining the finance team, Mr. Stack held a number of roles in the engineering team, including design, operations and project management.

During the first quarter of 2021, Brett Gellner, our Chief Development Officer, announced he will retire effective April 30, 2021. Mr. Gellner has been employed with TransAlta for almost 13 years and during this time he has fulfilled multiple roles in commercial, finance, growth and strategy and served as our Chief Financial Officer. Mr. Gellner has built a reputation amongst investors and the broader community as a highly respected key leader in the power industry. He was central in TransAlta's recent corporate transformations and developing the Clean Energy Investment Plan. Mr. Gellner will remain on TransAlta Renewables' Board of Directors.

The roles of Chief Operating Officer and Chief Development Officer will not be backfilled.

Board of Director Changes

On April 21, 2020, we announced that the Board appointed John P. Dielwart as Chair of the Board, upon his re-election as an independent director at TransAlta's annual shareholder meeting. As previously announced, Ambassador Gordon Giffin, the previous Chair of the Board, retired from the Board after serving as Chair since 2011.

Mr. Dielwart has served as an independent director on the Board since 2014, and has also served as the Chair of the Governance, Safety and Sustainability Committee and as a member of the Investment Performance Committee and the Audit, Finance and Risk Committee of the Board. 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.

Also effective April 21, 2020, Sandra Sharman joined the Board. Ms. Sharman leads the Human Resources, Communications, Marketing and Enterprise Real Estate teams at CIBC, supporting execution of business strategy and enabling a world-class culture. A proven business leader with over 30 years of human resources and financial services experience in both Canada and the US, Ms. Sharman has played a leading role in shaping an inclusive and collaborative culture at CIBC, focused on empowering and enabling employees to reach their full potential. Ms. Sharman assumed the leadership of Human Resources at CIBC in 2014 and added accountability for communications and public affairs in 2017. Since 2017, her portfolio has expanded to encompass purpose, brand, marketing and most recently, corporate real estate. Ms. Sharman earned her Masters of Business Administration (MBA) from Dalhousie University. At TransAlta, Ms. Sharman is a member of the Governance, Safety and Sustainability Committee and the Human Resources Committee.

Robert Flexon resigned from the Board effective Aug. 1, 2020. Mr. Flexon assumed the role of Chair of the Board of Directors of PG&E Corporation ("PG&E") and resigned from the Board due only to the potential for perceived conflicts of interests between PG&E and the Corporation.

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

Please refer to Note 4 of the consolidated financial statements within our 2020 Annual Integrated Report for significant events impacting both prior and current year results.

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, principal payments on lease liabilities, reclamation costs and provisions. This is the cash flow available to pay our interest and cash taxes, make distributions to our non-controlling partners, 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	2020	2019	2018
Segmented cash flow(1)			
Hydro	**83**	93	96
Wind and Solar	**241**	206	211
North American Gas(2)	**109**	99	228
Australian Gas	**114**	112	136
Alberta Thermal(3)(4)	**47**	214	279
Centralia(3)	**122**	54	63
Generation segmented cash flow	**716**	778	1,013
Energy Marketing	**114**	105	33
Corporate(5)	**(100)**	(92)	(107)
Total segmented cash flow	**730**	791	939
Total segmented cash flow – excluding the PPA Termination Payments	**730**	735	782

(1) Segmented cash flow is a non-IFRS measure and has no standardized meaning under IFRS. Please refer to the Additional IFRS Measures and Non-IFRS Measures section for further details.
(2) This segment was previously known as the Canadian Gas segment but was renamed with the acquisition of the US cogeneration facility in the second quarter of 2020.
(3) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(4) 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.
(5) Includes gains and losses on the total return swap.

Segmented cash flow generated by the business, after adjusting for the PPA Termination Payments, was consistent in 2020 compared to 2019, primarily due to higher performance in our Centralia, Wind and Solar, North American Gas and Energy Marketing segments. This was offset by lower power demand and production in our Alberta Thermal segment and the impact of the total return swap recognized in 2019 in the Corporate segment.

Cash flow in 2019, after adjusting for the PPA Termination Payments, was down $47 million in 2019 compared to 2018, mainly due to the expiry of the Mississauga Non-Utility Generator ("NUG") Enhanced Dispatch Contract (the "NUG Contract") and lower scheduled repayments on the Poplar Creek finance lease, partially offset by strong cash flows from Energy Marketing as well as lower sustaining capital expenditures.

Hydro

Year ended Dec. 31	2020	2019	2018
Production			
Energy contracted			
Alberta Hydro PPA assets (GWh)[1]	**1,703**	1,653	1,519
Other hydro energy (GWh)[1]	**353**	331	306
Energy merchant			
Other hydro energy (GWh)	**76**	61	81
Total energy production (GWh)	**2,132**	2,045	1,906
Ancillary service volumes (GWh)[2]	**2,857**	2,978	3,265
Gross installed capacity (MW)	**926**	926	926
Revenues			
Alberta Hydro PPA assets energy	**87**	101	90
Alberta Hydro PPA assets ancillary	**66**	90	104
Capacity payments received under Alberta Hydro PPA[3]	**60**	57	56
Other revenue[4]	**45**	44	41
Total gross revenues	**258**	292	291
Net payment relating to Alberta Hydro PPA[5]	**(106)**	(136)	(135)
Revenues	**152**	156	156
Fuel and purchased power	**8**	7	6
Comparable gross margin	**144**	149	150
Operations, maintenance and administration	**37**	36	38
Taxes, other than income taxes	**2**	3	3
Comparable EBITDA	**105**	110	109
Deduct:			
Sustaining capital:			
Routine capital	**12**	7	4
Planned major maintenance	**8**	7	8
Total sustaining capital expenditures	**20**	14	12
Productivity capital	**—**	1	1
Total sustaining and productivity capital	**20**	15	13
Provisions	**2**	—	—
Decommissioning and restoration costs settled	**—**	2	—
Hydro cash flow	**83**	93	96

(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 and 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 expired 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 that expired on Dec. 31, 2020.

2020

Production for 2020 increased by 87 GWh over 2019, primarily due to higher water resources.

Ancillary service volumes for 2020 decreased by 121 GWh compared to 2019. This was primarily due to the AESO procuring lower ancillary volumes in 2020. Additionally, there has been weaker market conditions for ancillary services, partially due to COVID-19 and reduced industrial demand in Alberta.

	2020	2019	2018
Gross Revenues per MWh			
Alberta Hydro PPA assets energy ($/MWh)	**$51**	$61	$59
Alberta Hydro PPA assets ancillary ($/MWh)	**$23**	$30	$32

In 2020, Alberta Hydro energy revenue per MWh of production decreased by approximately $10 per MWh, compared to 2019, as result of lower merchant prices in Alberta.

In 2020, Alberta Hydro ancillary revenue per MWh of production decreased by approximately $7 per MWh, compared to 2019. Lower realized prices were primarily due to unfavourable market conditions in Alberta in 2020. For further discussion on the market conditions and pricing, please refer to the Competitive Forces section of this MD&A.

Total gross revenues for 2020 decreased $34 million compared to 2019, as lower energy and ancillary services revenues resulted from lower Alberta pricing and lower demand for ancillary products, partially offset by higher water resources.

Comparable EBITDA for 2020 decreased by $5 million compared to 2019, from lower revenues partially offset by recoveries allocated by the AESO related to the AESO transmission line loss proceeding. For additional information, please see Note 36 Commitments & Contingencies within the financial statements.

Sustaining capital expenditures for 2020 were $6 million higher than in 2019, due to more planned outages in 2020.

Hydro's cash flow decreased by $10 million for 2020 compared to 2019 mainly due to lower EBITDA and higher sustaining capital spend, partially offset by lower settlements of decommissioning and restoration costs.

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 optimized 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.

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.

Wind and Solar

Year ended Dec. 31	2020	2019	2018
Availability (%)	**95.1**	95.0	95.4
Contract production (GWh)	**2,871**	2,395	2,363
Merchant production (GWh)	**1,198**	960	1,005
Total production (GWh)	**4,069**	3,355	3,368
Gross installed capacity (MW)(1)	**1,572**	1,495	1,382
Revenues	**334**	295	302
Fuel and purchased power	**25**	16	17
Comparable gross margin	**309**	279	285
Operations, maintenance and administration	**53**	50	50
Taxes, other than income taxes	**8**	8	8
Net other operating income(2)	**—**	(10)	(6)
Comparable EBITDA	**248**	231	233
Deduct:			
Sustaining capital:			
Routine capital	**—**	2	5
Planned major maintenance	**13**	11	8
Total sustaining capital expenditures	**13**	13	13
Productivity capital	**1**	—	2
Total sustaining and productivity capital	**14**	13	15
Provisions	**(8)**	—	—
Principal payments on lease liabilities	**1**	1	—
Decommissioning and restoration costs settled	**—**	1	1
Other(2)	**—**	10	6
Wind and Solar cash flow	**241**	206	211

(1) 2020 gross installed capacity includes the WindCharger battery storage facility and our proportionate share of the Skookumchuck wind facility. The 2020 and 2019 gross installed capacity includes the addition of Big Level and Antrim, partially offset by the reduction of wind turbines due to tower fires at Wyoming Wind and Summerview.
(2) Relates to insurance proceeds included in net other operating income.

2020

Availability for the year ended Dec. 31, 2020, was consistent with 2019, which was in line with our expectations.

Production for the year ended Dec. 31, 2020, increased 714 GWhs, mainly due to the Big Level and Antrim wind facilities commencing commercial operations in December 2019 and strong wind resources across all regions in 2020, in particular for our Alberta wind facilities.

Comparable EBITDA for 2020 increased by $17 million compared to 2019, primarily due to the addition of the Big Level and Antrim wind facilities and higher production, partially offset by insurance proceeds received in 2019, lower Alberta pricing and the planned expiry of certain wind power production incentives in 2019. In addition, during 2020, the AESO began issuing invoices pertaining to the AESO transmission line loss. Wind and Solar has been allocated $8 million in costs in 2020, which has been reflected in fuel and purchased power within the current year. For additional information, please refer to Note 36 Commitments & Contingencies within the financial statements.

Sustaining and productivity capital expenditures for 2020 were consistent with 2019.

Wind and Solar's cash flow increased by $35 million for the year ended Dec. 31, 2020, compared to the prior year, mainly due to higher comparable EBITDA and insurance proceeds received in 2019, partially offset by higher sustaining and productivity capital spend for Kent Hills foundation expenditures.

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 facilities 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.

North American Gas(1)

Year ended Dec. 31	**2020**	2019	2018
Availability (%)	**96.9**	94.8	93.3
Contract production (GWh)	**1,896**	1,655	1,620
Merchant production (GWh)(2)	**131**	262	172
Purchased power (GWh)(2)	**(198)**	(92)	(79)
Total production (GWh)	**1,829**	1,825	1,713
Gross installed capacity (MW)(3)	**974**	945	945
Revenues	**234**	238	407
Fuel and purchased power	**66**	74	99
Comparable gross margin	**168**	164	308
Operations, maintenance and administration	**49**	44	48
Taxes, other than income taxes	**2**	1	1
Net other operating income	**—**	(1)	—
Comparable EBITDA	**117**	120	259
Deduct:			
Sustaining capital:			
Routine capital	**4**	10	4
Planned major maintenance	**2**	8	16
Total sustaining capital expenditures	**6**	18	20
Productivity capital	**—**	—	2
Total sustaining and productivity capital	**6**	18	22
Provisions and other	**—**	—	9
Decommissioning and restoration costs settled	**2**	3	—
North American Gas cash flow	**109**	99	228

(1) This segment was previously known as the Canadian Gas segment but was renamed with the acquisition of the Ada facility in the second quarter of 2020. See the Corporate Strategy section of this MD&A and Note 4 of the consolidated financial statements for further details.
(2) Purchased power used for dispatch optimization has been separated from merchant production in the current year. Comparable periods have been adjusted to reflect this change.
(3) 2020 includes 29 MW for the acquisition of the Ada facility in the second quarter of 2020.

2020

Availability for the year ended Dec. 31, 2020, increased compared to 2019, primarily due to lower planned and unplanned outages at our Fort Saskatchewan, Sarnia and Ottawa facilities, partially offset by planned outages at the Ada facility.

Production was consistent with 2019. Higher customer demand at our Sarnia facility and the addition of the Ada facility was offset by lower Ontario market demand in 2020. Due to low power pricing in Ontario, we settled some customer power purchases with power purchased from the merchant market. Overall, 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 pass-through of fuel costs.

OM&A costs for 2020 were $5 million higher than in 2019, due to the addition of the new Ada facility and the new recontracted terms of the Fort Saskatchewan commercial agreement.

Comparable EBITDA for 2020 decreased by $3 million compared to 2019, mainly due to lower earnings at Fort Saskatchewan as the new commercial agreement was negatively impacted by lower merchant pricing in Alberta, partially offset by the addition of the Ada facility.

Sustaining capital expenditures in 2020 decreased by $12 million mainly due to a major planned outage for Sarnia in 2019.

Cash flow at North American Gas increased by $10 million for the year ended Dec. 31, 2020, compared to the prior year mainly due to lower sustaining capital, partially offset by lower comparable EBITDA.

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, 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.

Australian Gas

Year ended Dec. 31	2020	2019	2018
Availability (%)	**93.8**	90.6	94.0
Contract production (GWh)	**1,779**	1,832	1,814
Gross installed capacity (MW)	**450**	450	450
Revenues	**162**	160	165
Fuel and purchased power	**6**	5	4
Comparable gross margin	**156**	155	161
Operations, maintenance and administration	**32**	37	37
Comparable EBITDA	**124**	118	124
Deduct:			
Sustaining capital:			
Routine capital	**3**	2	2
Planned major maintenance	**6**	3	—
Total sustaining capital expenditures	**9**	5	2
Productivity capital	**1**	1	—
Total sustaining and productivity capital	**10**	6	2
Other	**—**	—	(14)
Australian Gas cash flow	**114**	112	136

2020

Availability for the year ended Dec. 31, 2020, increased compared to 2019, mainly due to unplanned outages in 2019.

Production for 2020 decreased compared to 2019, mainly due to changes in customer demand at the South Hedland facility. 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 pass-through of fuel costs.

Comparable EBITDA for the year ended Dec. 31, 2020, increased by $6 million compared to 2019, due to the deferral of legal costs associated with our dispute with Fortescue Metals Group Ltd ("FMG"), reduced staffing due to cost controls and the strengthening of the Australian dollar against the Canadian dollar.

Sustaining and productivity capital for 2020 increased by $4 million compared to 2019, mainly due to planned major maintenance at our Southern Cross facility.

Australian Gas' cash flow increased by $2 million in 2020, mainly due to higher comparable EBITDA, partially offset by higher sustaining capital expenditures.

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 pass-through 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 dispute 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.

Alberta Thermal[1]

Year ended Dec. 31	2020	2019	2018
Availability (%)	**84.8**	89.2	91.6
Contract production (GWh)	**5,851**	6,927	8,936
Merchant production (GWh)	**4,186**	5,932	5,304
Total production (GWh)	**10,037**	12,859	14,240
Gross installed capacity (MW)[2]	**2,866**	3,229	3,231
Revenues	**659**	823	901
Fuel, carbon compliance and purchased power[3]	**391**	449	526
Comparable gross margin	**268**	374	375
Operations, maintenance and administration	**131**	138	171
Taxes, other than income taxes	**15**	13	13
Termination of Sundance B and C PPAs	**—**	(56)	(157)
Net other operating income	**(40)**	(40)	(41)
Comparable EBITDA[3]	**162**	319	389
Deduct:			
Sustaining capital:			
Routine capital	**16**	15	17
Mine capital	**7**	23	42
Planned major maintenance	**62**	34	15
Total sustaining capital expenditures	**85**	72	74
Productivity capital	**1**	6	12
Total sustaining and productivity capital	**86**	78	86
Provisions	**—**	(6)	(10)
Principal payments on lease liabilities	**20**	16	14
Decommissioning and restoration costs settled	**9**	17	19
Other	**—**	—	1
Alberta Thermal cash flow	**47**	214	279

(1) The Canadian Coal segment was renamed Alberta Thermal in the third quarter of 2020.
(2) All years include 406 MW for Sundance Unit 5, which is temporarily mothballed. Sheerness Unit 2's capacity was increased in 2020 following a generator rewind and final testing. 2019 and 2018 also include 368 MW for Sundance Unit 3, which was temporarily mothballed and then retired during the third quarter of 2020. In addition, the Keephills 3 and Genesee 3 asset swap resulted in a net 2 MW reduction of capacity that occurred in the fourth quarter of 2019.
(3) In 2020, the interest on the line loss provision was reclassified from fuel, carbon compliance and purchased power to interest expense.

Supplemental disclosure	2020	2019	2018
Comparable EBITDA – excluding the PPA Termination Payments	**162**	263	232
Alberta Thermal cash flow – excluding the PPA Termination Payments	**47**	158	122

2020

Availability for the year was lower compared to 2019 due to the Sundance Unit 6 planned turnaround and conversion to gas outage occurring in late 2020 and higher unplanned outages and derates. The Sundance Unit 6 return to service was delayed due to unexpected issues identified during recommissioning. Our Keephills Unit 2 has experienced increased outages as we approach the 2021 turnaround outage. Increased derates are attributed to our conversion to gas transition plan and our consumption of lower-quality coal inventory.

Production for the year ended Dec. 31, 2020, decreased 2,822 GWh compared to 2019. This was largely a result of curtailments and dispatch optimization resulting in lower merchant production in the Alberta Thermal fleet due to reduced industrial demand in the province and the impact of COVID-19 on demand generally. Production also decreased due to lower availability.

Revenue for the year ended Dec. 31, 2020, decreased by $164 million compared to 2019, mainly due to lower merchant production.

	2020	2019	2018
Revenues per MWh	**$66**	$64	$63
Fuel, carbon compliance and purchased power per MWh	**$39**	$35	$37

In 2020, revenue per MWh of production increased by $2 per MWh in 2020 compared with 2019 primarily due to higher realized prices as a result of optimizing production during periods of favourable pricing and hedging positions minimizing the impact of unfavourable market pricing.

In 2020, fuel, carbon compliance and purchased power costs per MWh of production increased by $4 per MWh compared with 2019. Costs per MWh increased due to fixed coal costs spread over less volumes, resulting in increased costs per MWh.

We continued to co-fire with natural gas, when economic. Natural gas combustion produces fewer GHG emissions than coal combustion, which lowers our GHG compliance costs.

OM&A costs were lower in 2020 compared to 2019 as a result of strong cost controls, reduced staffing in line with conversion to gas transition plans, and a reflection of lower production.

Excluding the PPA Termination Payments, comparable EBITDA for the year ended Dec. 31, 2020, decreased $101 million compared to 2019. Merchant production was lower due to unfavourable market conditions and higher fuel costs.

For the year ended Dec. 31, 2020, sustaining capital expenditures increased by $13 million compared to 2019 mainly due to the major maintenance that occurred during the Sheerness dual-fuel conversion and the Sundance Unit 6 turnaround.

Alberta Thermal cash flow for the year ended Dec. 31, 2020, excluding the PPA Termination Payments, decreased by $111 million compared to 2019 mainly due to lower comparable EBITDA, increased sustaining and productivity capital expenditures and the early settlement of mining equipment leases, partially offset by the deferral of decommissioning expenditures due to COVID-19.

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 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 March 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 pass-through 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.

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 that included 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.

Alberta Thermal's 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.

Centralia(1)

Year ended Dec. 31	2020	2019	2018
Availability (%)	**76.2**	74.0	60.2
Adjusted availability (%)(2)	**90.2**	83.5	84.6
Contract sales volume (GWh)	**3,338**	3,329	3,329
Merchant sales volume (GWh)	**5,571**	7,691	5,704
Purchased power (GWh)	**(3,775)**	(3,865)	(3,665)
Total production (GWh)	**5,134**	7,155	5,368
Gross installed capacity (MW)	**1,340**	1,340	1,340
Revenues	**483**	559	471
Fuel and purchased power	**279**	416	314
Comparable gross margin	**204**	143	157
Operations, maintenance and administration	**60**	67	61
Taxes, other than income taxes	**5**	3	5
Comparable EBITDA	**139**	73	91
Deduct:			
Sustaining capital:			
Routine capital	**3**	2	2
Planned major maintenance	**7**	5	11
Total sustaining capital expenditures	**10**	7	13
Productivity capital	**—**	1	—
Total sustaining and productivity capital	**10**	8	13
Principal payments on lease liabilities	**—**	—	4
Decommissioning and restoration costs settled	**7**	11	11
Centralia cash flow	**122**	54	63

(1) The US Coal segment was renamed Centralia in the third quarter of 2020.
(2) Adjusted for dispatch optimization.

2020

Adjusted availability for the year increased compared to 2019 due to lower forced outages and derates in 2020. In the first half of 2019, Centralia Unit 1 had significant derates that were resolved and not experienced in 2020.

Production decreased by 2,021 GWh in 2020 compared to 2019 due mainly to lower merchant pricing throughout 2020 and timing of dispatch optimization. In 2020, both Centralia units were taken out of service in February and March as a result of seasonally lower prices in the Pacific Northwest, whereas in 2019 both units remained in service into April due to higher prices in the Pacific Northwest.

OM&A costs were $7 million lower in 2020 compared to 2019 mainly due to lower levels of maintenance required to support an almost 30 per cent decrease in production and strong cost controls.

Comparable EBITDA increased by $66 million compared to 2019, primarily due to increased benefits from dispatch optimization in 2020 and from an isolated and extreme pricing event in March 2019 for $25 million where Centralia was unable to commit one of its units to physical production for day-ahead supply due to an unplanned forced outage repair. In addition, comparable EBITDA in 2020 increased with the strengthening of the US dollar relative to the Canadian dollar throughout the year.

Sustaining and productivity capital expenditures for 2020 were $2 million higher than 2019 mainly due to increased planned outage work performed in 2020 during the reserve shutdown.

Centralia's cash flow for 2020 increased by $68 million compared to the prior year, mainly due to higher comparable EBITDA and deferral of decommissioning expenditures due to COVID-19, partially offset by higher sustaining capital spend.

2019

Adjusted availability for 2019 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 in 2019 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.

Centralia's cash flow for 2019 decreased by $9 million compared to 2018, mainly due to lower comparable EBITDA, partially offset by lower sustaining and productivity capital spend.

Energy Marketing

Year ended Dec. 31	**2020**	2019	2018
Revenues and comparable gross margin	**143**	119	67
Operations, maintenance and administration	**30**	30	24
Comparable EBITDA	**113**	89	43
Deduct:			
Provisions and other	**(1)**	(16)	10
Energy Marketing cash flow	**114**	105	33

2020

Comparable EBITDA for 2020 increased by $24 million compared to 2019. Results were primarily from continued strong performance in both power and natural gas markets. Gains were realized from short-term strategies across various geographic regions aided by market and price volatility. 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. OM&A spending for 2020 and 2019 was similar.

Energy Marketing's cash flows for 2020 increased by $9 million compared to 2019 mainly due to higher comparable EBITDA, partially offset by changes in emissions obligations and prepaid balances for transmission rights.

2019

Comparable EBITDA for 2019 increased by $46 million compared to 2018 results due to strong results from all Energy 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 changes in emissions obligations and prepaid balances for transmission rights.

Corporate

Year ended Dec. 31	2020	2019	2018
Operations, maintenance, and administration	**80**	73	86
Taxes, other than income taxes	**1**	1	1
Net other operating loss	**—**	2	—
Comparable EBITDA	**(81)**	(76)	(87)
Deduct:			
Sustaining capital:			
Routine capital	**14**	12	16
Total sustaining capital expenditures	**14**	12	16
Productivity capital	**1**	—	4
Total sustaining and productivity capital expenditures	**15**	12	20
Provisions	**—**	—	—
Principal payments on lease liabilities	**4**	4	—
Corporate cash flow	**(100)**	(92)	(107)

Supplemental disclosure	2020	2019	2018
Corporate cash flow	**(100)**	(92)	(107)
Total return swap (gains) losses	**2**	(13)	(1)
Adjusted Corporate cash flow	**(98)**	(105)	(108)

2020

Our Corporate overhead costs in 2020 were $81 million, an increase of $5 million compared to $76 million in 2019, primarily due to realized gains and losses from the total return swap. A portion of the settlement cost of our employee share-based payment plans is fixed by entering into total return swaps, which are cash settled every quarter. Excluding the impact of the total return swap, Corporate overhead costs for 2020 decreased by $10 million compared to 2019, mainly due to lower legal fees and lower labour and reduced travel costs, partially offset by additional costs to support growth and development projects, centralization of shared services to the Corporate segment and additional costs incurred to support COVID-19 protocols.

Corporate cash flow, excluding the impact of the total return swap, was also lower in 2020 compared to 2019 due to slightly higher sustaining and productivity capital spend on information technology.

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 principal payments on lease liabilities. In addition, we realized a net gain of $13 million from the total return swap, which was mostly offset by higher legal costs. 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.

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, 2020, 2019 and 2018. 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, deconsolidated comparable EBITDA by segment, 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:

- Comparable EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.
- Certain assets we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe it is more appropriate to reflect the payments we receive under the contracts as a capacity payment in our revenues instead of as finance lease income and a decrease in finance lease receivables.
- We 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.
- Coal inventory writedowns are not included as these are non-cash adjustments that are not reflective of our core business results upon conversion to gas. To accelerate our conversion to gas plans, a decision was made to accelerate the mine shutdown to 2021.
- In December 2016, we agreed to terminate our existing arrangement with the Independent Electricity System Operator relating to our Mississauga cogeneration facility in Ontario and entered into 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 Highvale mine to the Keephills 3 facility. Upon termination of this agreement in the fourth quarter of 2019, the Highvale 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.
- During the fourth quarter of 2020, we acquired a 49 per cent interest in the Skookumchuck wind facility, which is treated as an equity investment under IFRS and our proportionate share of the net earnings is reflected as equity income on the statement of earnings under IFRS. As this investment is part of our regular power-generating operations, we have included our proportionate share of the comparable EBITDA of Skookumchuck in our total comparable EBITDA. In addition, in the Wind and Solar comparable results, we have included our proportionate share of revenues and expenses to reflect the full operational results of this investment. We have not included EMG's comparable EBITDA in our total comparable EBITDA as it does not represent our regular power-generating operations.
- During the fourth quarter of 2020, we recorded an onerous contract provision on the coal supply contract for Sheerness as we accelerated our plans to eliminate coal as a fuel source by the end of 2021. This is a one-time charge that is not reflective of ongoing operations and therefore has been removed for comparable EBITDA.

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

Year ended Dec. 31	2020	2019	2018
Net earnings (loss) attributable to common shareholders	**(336)**	52	(248)
Net earnings attributable to non-controlling interests	**34**	94	108
Preferred share dividends	**49**	30	50
Net earnings (loss)	**(253)**	176	(90)
Adjustments to reconcile net income to comparable EBITDA			
Income tax expense (recovery)	**(50)**	17	(6)
Gain on sale of assets and other	**(9)**	(46)	(1)
Foreign exchange (gain) loss	**(17)**	15	15
Net interest expense	**238**	179	250
Equity income	**(1)**	—	—
Depreciation and amortization	**654**	590	574
Comparable reclassifications			
Decrease in finance lease receivables	**17**	24	59
Mine depreciation included in fuel cost	**145**	121	140
Australian interest income	**4**	4	4
Unrealized mark-to-market (gains) losses	**46**	(33)	38
Adjustments to earnings to arrive at comparable EBITDA			
Impact of Sheerness going off coal(1)	**29**	—	—
Impacts associated with Mississauga recontracting(2)	**—**	—	105
Gain on termination of Keephills 3 coal rights contract	**—**	(88)	—
Coal inventory writedown	**37**	—	—
Asset impairment (3)	**84**	25	73
Share of adjusted EBITDA from joint venture(4)	**3**	—	—
Comparable EBITDA	**927**	984	1,161
Comparable EBITDA – excluding the PPA Termination Payments	**927**	928	1,004

(1) During the fourth quarter of 2020, a decision was made to accelerate our plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. As such, the existing coal supply contract has been classified as an onerous contract and the remaining expected contract payments have been accrued for in the current year.
(2) Impacts associated with Mississauga facility 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).
(3) Asset impairment for 2020 primarily includes the retirement of Sundance Unit 3 ($70 million), impairment on a BC hydro facility ($2 million), impairment on the Centralia land ($9 million) and asset impairments resulting from changes in discount rates for the decommissioning and restoration liabilities for our retired assets (2019 — $141 million increase for the decommissioning and restoration liability at the Centralia mine, $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 Centralia; 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). For further details, please refer to the Critical Accounting Estimates section of this MD&A.
(4) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

Funds from Operations and Free Cash Flow

Funds from Operations ("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	2020	2019	2018
Cash flow from operating activities[1][2]	702	849	820
Change in non-cash operating working capital balances	(89)	(121)	44
Cash flow from operations before changes in working capital	**613**	728	864
Adjustments			
Share of adjusted FFO from joint venture[2]	3	—	—
Decrease in finance lease receivable	17	24	59
Coal inventory writedown	37	—	—
Other	15	5	4
FFO	**685**	**757**	**927**
Deduct:			
Sustaining capital[2]	(157)	(141)	(150)
Productivity capital	(4)	(9)	(21)
Dividends paid on preferred shares	(39)	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	(102)	(111)	(169)
Principal payments on lease liabilities[2]	(25)	(21)	(18)
Other	—	—	(5)
FCF	**358**	435	524
Weighted average number of common shares outstanding in the year	275	283	287
FFO per share	**2.49**	2.67	3.23
FCF per share	**1.30**	1.54	1.83

(1) 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

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

Year ended Dec. 31	2020	2019	2018
Comparable EBITDA[1]	927	984	1,161
Provisions and other	7	13	(9)
Interest expense[2]	(192)	(174)	(187)
Current income tax expense[2]	(35)	(35)	(28)
Realized foreign exchange gain (loss)	8	(6)	5
Decommissioning and restoration costs settled[2]	(18)	(34)	(31)
Other cash and non-cash items	(12)	9	16
FFO	**685**	757	927
Deduct:			
Sustaining capital[2]	(157)	(141)	(150)
Productivity capital	(4)	(9)	(21)
Dividends paid on preferred shares	(39)	(40)	(40)
Distributions paid to subsidiaries' non-controlling interests	(102)	(111)	(169)
Principal payments on lease liabilities[2]	(25)	(21)	(18)
Other	—	—	(5)
FCF	**358**	435	524

(1) 2019 and 2018 amounts include the PPA Termination Payments. See the Significant and Subsequent Events section for further details.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

Supplemental disclosure	**2020**	2019	2018
FFO – excluding the PPA Termination Payments	**685**	701	770
FCF – excluding the PPA Termination Payments	**358**	379	367
FFO per share – excluding the PPA Termination Payments	**2.49**	2.48	2.68
FCF per share – excluding the PPA Termination Payments	**1.30**	1.34	1.28

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

FCF in 2019, after adjusting for the PPA Termination Payments, increased $12 million compared to 2018, 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 section of this MD&A.

The table below bridges our reported EBITDA of our owned assets to our comparable EBITDA:

Year ended Dec. 31, 2020	Reported	Adjustments[1]	Joint venture investment[2]	Comparable total
Revenues	2,101	70	3	**2,174**
Fuel, carbon compliance and purchased power	968	(186)	—	**782**
Gross margin	1,133	256	3	**1,392**
Operations, maintenance and administration	472	—	—	**472**
Asset impairment	84	(84)	—	**—**
Taxes, other than income taxes	33	—	—	**33**
Net other operating income (expense)	(11)	(29)	—	**(40)**
Comparable EBITDA	555	369	3	**927**

(1) Refer to the reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA table above for details of all adjustments.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

Fourth Quarter

Consolidated Financial Highlights

Three months ended Dec. 31	2020	2019
Adjusted availability (%)(1)	**87.1**	91.6
Production (GWh)(1)	**7,704**	8,153
Revenues	**544**	609
Fuel, carbon compliance and purchased power(3)	**327**	286
Operations, maintenance and administration	**118**	127
Net earnings (loss) attributable to common shareholders	**(167)**	66
Cash flow from operating activities	**110**	181
Comparable EBITDA(2),(3)	**234**	243
FFO(2)	**161**	189
FCF(2)	**52**	121
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.61)**	0.24
FFO per share(2)	**0.59**	0.67
FCF per share(2)	**0.19**	0.43
Dividends declared per common share(4)	**0.09**	0.04
Dividends declared per preferred share(5)	**0.50**	0.26

(1) Adjusted availability and production include all generating assets that we operate and finance leases and exclude hydro assets and equity investments.
(2) 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. Please 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.
(3) During the fourth quarter of 2020, we reclassified interest expense on the AESO transmission line loss from fuel costs to interest expense.
(4) Dividends declared vary year over year due to timing of dividend declarations.
(5) 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

During the fourth quarter of 2020, the Corporation demonstrated strong performance at the Wind and Solar and North American Gas segments with the addition of new facilities,and higher wind resources, which was more than offset by the expected impact on EBITDA of the Sundance Unit 6 turnaround and conversion to gas outage at Alberta Thermal and high levels of volatility in the market impacting the Energy Marketing segment.

FCF in the fourth quarter of 2020 was $52 million compared to $121 million in the same period of 2019, mainly due to lower comparable EBITDA, higher interest expense, higher sustaining capital expenditures, increased distributions paid to subsidiary non-controlling interests and final settlement of lease payments at the Highvale mine. FFO was $161 million, which was $28 million lower than the fourth quarter of 2019, also mainly due to lower comparable EBITDA and higher interest expense relating to new debt issuances.

Net loss attributable to common shareholders in the fourth quarter of 2020 was $167 million compared to net earnings of $66 million in the same period of 2019, a decrease of $233 million. The net loss in 2020 was impacted by lower availability, which reduced revenues, the additional coal inventory writedowns of $15 million from an increased cost of coal and higher depreciation from the acceleration of the Highvale mine closure of $8 million, the onerous contract provision recognized on the coal contract for Sheerness for $29 million and higher interest expense associated with the TEC Offering and the second tranche of the Brookfield Investment, partially offset by lower asset impairments. The prior year also benefited from the gain on the termination of the Keephills 3 coal rights contract of $88 million and the gain on the sale of Genesee 3 of $77 million.

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, 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, 2020 and 2019 is as follows:

Three months ended Dec. 31	2020	2019
Segmented cash flow(1)		
Hydro	**11**	13
Wind and Solar	**80**	72
North American Gas(2)	**28**	22
Australian Gas	**24**	25
Alberta Thermal(3)	**(10)**	37
Centralia(3)	**28**	25
Generation segmented cash flow	**161**	194
Energy Marketing	**15**	31
Corporate(4)	**(28)**	(29)
Total segmented cash flow	**148**	196

(1) 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. Please 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) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020
(3) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(4) Includes gains and losses on the total return swap.

Availability for the three months ended Dec. 31, 2020, was lower than with the same period in 2019, mainly due to the Sundance Unit 6 planned turnaround and conversion to gas outage at Alberta Thermal in late 2020, which was partially offset by higher availability at Centralia due to lower unplanned outages and derates. Production was lower for the three months ended Dec. 31, 2020, compared to the same period in 2019, primarily due to lower availability and economic dispatch at Alberta Thermal, partially offset by higher wind resources at Wind and Solar.

Segmented cash flow generated by the business totalled $148 million in the fourth quarter, a decrease of $48 million compared with last year's performance. The decrease in cash flow is largely due to lower availability resulting from planned outages and additional sustaining capital spend resulting from the Sundance Unit 6 turnaround and conversion to gas outages at Alberta Thermal and lower cash flows from Energy Marketing due to market volatility. This was partially offset by increased segmented cash flows at North American Gas with the addition of the Ada facility, lower capital expenditures and higher margins at our Sarnia facility. In addition, segmented cash flows at Wind and Solar increased as a result of the addition of the Skookumchuck wind facility and full year of operations for Big Level and Antrim.

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	2020	2019
Net earnings (loss) attributable to common shareholders	**(167)**	66
Net earnings attributable to non-controlling interests	**5**	27
Preferred share dividends	**19**	10
Net earnings (loss)	**(143)**	103
Adjustments to reconcile net income to comparable EBITDA		
Income tax expense	**(25)**	40
Gain on sale of assets and other	**(7)**	(64)
Foreign exchange (gain) loss	**(2)**	(3)
Net interest expense	**63**	18
Equity income	**(1)**	—
Depreciation and amortization	**173**	154
Comparable reclassifications		
Decrease in finance lease receivables	**6**	5
Mine depreciation included in fuel cost	**58**	31
Australian interest income	**1**	1
Unrealized mark-to-market (gains) losses	**47**	(1)
Adjustments to earnings to arrive at comparable EBITDA		
Inventory writedown	**15**	—
Impact of Sheerness going off-coal(1)	**29**	—
Asset impairment charge(2)	**17**	47
Gain on termination of Keephills 3 coal rights contract	**—**	(88)
Share of adjusted EBITDA from joint venture(3)	**3**	—
Comparable EBITDA	**234**	243

(1) During the fourth quarter of 2020, a decision was made to accelerate our plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. As such, the existing coal supply contract has been classified as an onerous contract and the remaining expected contract payments have been accrued for in the current year.
(2) Asset impairment charges for the three months ended Dec. 31, 2020, primarily relates to the impairment on the Centralia land ($9 million) relating to Centralia land and asset impairments resulting from changes in discount rates for the decommissioning and restoration liabilities for our retired assets (2019 — $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).
(3) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

A summary of our comparable EBITDA by segment for the three months ended Dec. 31, 2020 and 2019 is as follows:

Three months ended Dec. 31	2020	2019
Comparable EBITDA		
Hydro	**22**	18
Wind and Solar	**77**	80
North American Gas(1)	**32**	29
Australian Gas	**31**	28
Alberta Thermal(2)	**41**	55
Centralia(2)	**30**	29
Energy Marketing	**23**	26
Corporate	**(22)**	(22)
Total Comparable EBITDA	**234**	243

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

Comparable EBITDA decreased by $9 million for the fourth quarter 2020, compared to 2019, primarily as a result of:

- Hydro results were $4 million higher due to increased revenues from higher water resources and lower fuel and purchased power costs primarily resulting from allocated AESO transmission line loss recoveries.
- Wind and Solar results were down $3 million mainly due to provisions for the AESO transmission line loss and insurance proceeds benefiting 2019, partially offset by higher production volumes and additional earnings from Skookumchuck.
- Our North American Gas business was up $3 million mainly due to the addition of the new Ada facility and higher margins at our Sarnia facility.
- Australian Gas was up $3 million, mainly due to lower legal costs.
- Our Alberta Thermal results were down $14 million mainly due to lower production and increased fuel costs incurred from the acceleration of the Highvale mine closing and higher costs of coal.
- Centralia results were consistent with the prior year's fourth quarter results as lower revenues were offset with decreases in fuel and purchased power costs and lower OM&A due to dispatch optimization.
- Energy Marketing's comparable EBITDA was down $3 million, mainly due to continued high levels of volatility in the market.
- Corporate costs were consistent with the prior year's fourth quarter results. Impacts from the total return swap on our share-based payment plans were similar in 2020 compared to 2019.

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, 2020 and 2019:

Three months ended Dec. 31	**2020**	2019
Cash flow from operating activities	**110**	181
Change in non-cash operating working capital balances	**25**	1
Cash flow from operations before changes in working capital	**135**	182
Adjustments		
Share of adjusted FFO from joint venture[1]	**3**	—
Decrease in finance lease receivable	**6**	5
Coal inventory writedown	**15**	—
Other	**2**	2
FFO	**161**	189
Deduct:		
Sustaining capital[1]	**(58)**	(30)
Productivity capital	**(3)**	(2)
Dividends paid on preferred shares	**(9)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(29)**	(22)
Principal payments on lease liabilities[1]	**(10)**	(5)
Other	**—**	1
FCF	**52**	121
Weighted average number of common shares outstanding in the period	**273**	280
FFO per share	**0.59**	0.67
FCF per share	**0.19**	0.43

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

The table below provides a reconciliation of our comparable EBITDA to our FFO and FCF for the three months ended Dec. 31, 2020 and 2019:

Three months ended Dec. 31	2020	2019
Comparable EBITDA	**234**	243
Provisions	**(10)**	(1)
Interest expense(1)	**(56)**	(41)
Current income tax expense(1)	**5**	(7)
Realized foreign exchange gain (loss)	**(1)**	1
Decommissioning and restoration costs settled(1)	**(5)**	(10)
Other non-cash items	**(6)**	4
FFO	**161**	189
Deduct:		
Sustaining capital(1)	**(58)**	(30)
Productivity capital	**(3)**	(2)
Dividends paid on preferred shares	**(9)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(29)**	(22)
Principal payments on lease liabilities(1)	**(10)**	(5)
Other	**—**	1
Comparable FCF	**52**	121
Weighted average number of common shares outstanding in the period	**273**	280
Comparable FFO per share	**0.59**	0.67
Comparable FCF per share	**0.19**	0.43

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

The table below bridges our reported EBITDA of our owned assets to our comparable EBITDA:

Year ended Dec. 31, 2020	Reported	Adjustments(1)	Joint venture investment(2)	Comparable total
Revenues	544	56	3	**603**
Fuel, carbon compliance and purchased power	327	(74)	—	**253**
Gross Margin	217	130	3	**350**
Operations, maintenance and administration	118	—	—	**118**
Asset impairment	17	(17)	—	**—**
Taxes, other than income taxes	8	—	—	**8**
Net other operating income (expense)	19	(29)	—	**(10)**
Comparable EBITDA	55	176	3	**234**

(1) Please refer to the reconciliation of net earnings (loss) attributable to common shareholders to comparable EBITDA table above for details of all adjustments.
(2) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.

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 Centralia. Typically, hydroelectric 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 2020	Q2 2020	Q3 2020	**Q4 2020**
Revenues	606	437	514	**544**
Comparable EBITDA	220	217	256	**234**
FFO	172	159	193	**161**
Net earnings (loss) attributable to common shareholders	27	(60)	(136)	**(167)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[1]	0.10	(0.22)	(0.50)	**(0.61)**

	Q1 2019	Q2 2019	Q3 2019	Q4 2019
Revenues	648	497	593	609
Comparable EBITDA	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[1]	(0.23)	—	0.18	0.24

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

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

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

- Revenues declined due to weaker market conditions in 2020 as a result of COVID-19 and low oil prices;
- Impact of Sheerness going off-coal, which has resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in the fourth quarter of 2020;
- Coal inventory writedowns in the third and fourth quarters of 2020;
- Impact of the updated provision estimates for the AESO transmission line loss during the last three quarters of 2020;
- Significant foreign exchange gains in the last three quarters of 2020 more than offset foreign exchange losses experienced during the first quarter of 2020, while 2019 experienced overall foreign exchange losses for the year;
- Gains relating to the Keephills 3 and Genesee 3 swap in the fourth quarter of 2019;
- Effects of impairments and reversals during the second, third and fourth quarters of 2020 and the third and fourth quarters of 2019;
- Effects of changes in decommissioning and restoration provision in the third quarter of 2020 and third quarter of 2019;
- Effects of changes in useful lives of certain assets during the third quarter of 2020 and 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 $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 2020.

Funds from Operations before Interest to Adjusted Interest Coverage

For the year ended Dec. 31	2020	2019	2018
FFO[1]	**685**	757	927
Less: PPA Termination Payments	**—**	(56)	(157)
Add: Interest on debt, exchangeable debentures and leases, net of interest income and capitalized interest[2]	**182**	166	174
FFO before interest	**867**	867	944
Interest on debt, exchangeable securities and leases, net of interest income[2][3]	**185**	172	176
Add: 50 per cent of dividends paid on preferred shares[3]	**22**	20	20
Adjusted interest	**207**	192	196
FFO before interest to adjusted interest coverage (times)	**4.2**	4.5	4.8

(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.
(2) The interest on tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.
(3) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.

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 in 2020 compared to 2019, mainly due to lower FFO before interest.

Adjusted FFO to Adjusted Net Debt

As at Dec. 31	2020	2019	2018
FFO[1][2]	**685**	757	927
Less: PPA Termination Payments[1]	**—**	(56)	(157)
Add: 100 per cent of interest paid on exchangeable preferred shares [3]	**5**	—	—
Less: 50 per cent of dividends paid on preferred shares[1][3]	**(22)**	(20)	(20)
Adjusted FFO[1]	**668**	681	750
Period-end long-term debt[4]	**3,361**	3,212	3,267
Exchangeable securities	**730**	326	—
Less: 100 per cent of exchangeable preferred shares[3]	**(400)**	—	—
Less: Cash and cash equivalents	**(703)**	(411)	(89)
Less: Principal portion of TransAlta OCP restricted cash	**(11)**	(10)	(27)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares[3]	**671**	471	471
Fair value asset of hedging instruments on debt[5]	**(2)**	(7)	(10)
Adjusted net debt[6]	**3,646**	3,581	3,612
Adjusted FFO to adjusted net debt (%)	**18.3**	19.0	20.8

(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) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.
(4) Includes lease liabilities and tax equity financing.
(5) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2020, Dec. 31, 2019, and Dec. 31, 2018.
(6) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.

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 2019, partially due to higher adjusted net debt. We reached the low end of our target range of 20 to 25 per cent in 2018.

Adjusted Net Debt to Adjusted Comparable EBITDA

As at Dec. 31	2020	2019	2018
Period-end long-term debt(1)	**3,361**	3,212	3,267
Exchangeable securities	**730**	326	—
Less: 100 per cent of exchangeable preferred shares(2)	**(400)**	—	—
Less: Cash and cash equivalents	**(703)**	(411)	(89)
Less: Principal portion of TransAlta OCP restricted cash	**(11)**	(10)	(27)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(2)	**671**	471	471
Fair value asset of hedging instruments on debt(3)	**(2)**	(7)	(10)
Adjusted net debt(4)	**3,646**	3,581	3,612
Comparable EBITDA(5)	**927**	984	1,161
Less: PPA Termination Payments(5)	**—**	(56)	(157)
Adjusted comparable EBITDA(5)	**927**	928	1,004
Adjusted net debt to adjusted comparable EBITDA (times)	**3.9**	3.9	3.6

(1) Includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.
(3) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2020, Dec. 31, 2019, and Dec. 31, 2018.
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in the amounts.
(5) Last 12 months.

Our target for adjusted net debt to comparable EBITDA is 3.0 to 3.5 times. Our adjusted net debt to comparable EBITDA ratio was consistent to 2019, as adjusted net debt only increased slightly during the year.

Deconsolidated Net Debt to Deconsolidated Comparable EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to comparable EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage, excluding the portion of TransAlta Renewables and TransAlta Cogeneration L.P. ("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	2020	2019	2018
Period-end long-term debt(1)	**3,361**	3,212	3,267
Exchangeable securities	**730**	326	—
Less: 100 per cent of exchangeable preferred shares(2)	**(400)**	—	—
Less: Cash and cash equivalents	**(703)**	(411)	(89)
Add: TransAlta Renewables cash and cash equivalents(3)	**582**	63	73
Less: Principal portion of TransAlta OCP restricted cash	**(11)**	(10)	(27)
Add: 50 per cent of issued preferred shares(2)	**671**	471	471
Fair value asset of hedging instruments on debt(4)	**(2)**	(7)	(10)
Less: TransAlta Renewables long-term debt	**(692)**	(961)	(932)
Less: US tax equity financing and South Hedland debt(5)	**(905)**	(145)	(28)
Deconsolidated net debt	**2,631**	2,538	2,725
Comparable EBITDA(6)(7)	**927**	984	1,161
Less: PPA Termination Payments(6)	**—**	(56)	(157)
Less: TransAlta Renewables comparable EBITDA(6)	**(462)**	(438)	(430)
Less: TA Cogen comparable EBITDA(6)	**(54)**	(80)	(181)
Less: comparable EBITDA from equity accounted investments(8)	**(3)**	—	—
Add: Dividends from TransAlta Renewables(6)	**151**	151	151
Add: Dividends from TA Cogen(6)	**17**	37	86
Deconsolidated comparable EBITDA(6)(7)	**576**	598	630
Deconsolidated net debt to deconsolidated comparable EBITDA(6)(7) (times)	**4.6**	4.2	4.3

(1) Includes lease liabilities and tax equity financing.
(2) Exchangeable preferred shares are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.
(3) In the second quarter of 2020, we adjusted the calculation to remove the portion of cash relating to TransAlta Renewables' cash and cash equivalents to reflect deconsolidated cash. Prior periods have also been updated.
(4) Included in risk management assets and/or liabilities on the consolidated financial statements as at Dec. 31, 2020, Dec. 31, 2019, and Dec. 31, 2018.
(5) Relates to assets where TransAlta Renewables has economic interests.
(6) Last 12 months.
(7) During the fourth quarter of 2020, we revised comparable EBITDA to exclude the interest on the AESO transmission line loss.
(8) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.

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 increased compared with 2019, as higher deconsolidated net debt was partially offset by higher deconsolidated comparable EBITDA.

Deconsolidated Comparable EBITDA by Segment

Comparable EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated EBITDA is used in key planning and credit metrics and segment results highlight the operating performance of assets held directly at TransAlta that are comparable from period to period.

A reconciliation of comparable EBITDA to deconsolidated comparable EBITDA by segment results is set out below:

			2020			2019			2018
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**105**	**21**		110	18		109	17	
Wind and Solar	**248**	**256**		231	238		233	218	
North American Gas	**117**	**80**		120	82		259	84	
Australian Gas	**124**	**125**		118	120		124	130	
Alberta Thermal	**162**	**—**		319	—		389	—	
Centralia	**139**	**—**		73	—		91	—	
Energy Marketing	**113**	**—**		89	—		43	—	
Corporate	**(81)**	**(20)**		(76)	(20)		(87)	(19)	
Comparable EBITDA[1][2]	**927**	**462**	**465**	984	438	546	1,161	430	731
Less: TA Cogen comparable EBITDA			**(54)**			(80)			(181)
Less: Termination of Sundance B and C PPAs[1]			**—**			(56)			(157)
Less: EBITDA from joint venture investments[3]			**(3)**			—			—
Add: Dividend from TransAlta Renewables[1]			**151**			151			151
Add: Dividend from TA Cogen[1]			**17**			37			86
Deconsolidated TransAlta comparable EBITDA			**576**			598			630

(1) Last 12 months.
(2) During the fourth quarter of 2020, we revised comparable EBITDA to exclude the interest on the AESO transmission line loss.
(3) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.

Deconsolidated FFO

The Corporation has set a target 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:

	2020			2019			2018		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**702**	**267**		849	331		820	385	
Change in non-cash operating working capital balances	**(89)**	**31**		(121)	(23)		44	5	
Cash flow from operations before changes in working capital	**613**	**298**		728	308		864	390	
Adjustments:									
Decrease in finance lease receivable	**17**	**—**		24	—		59	—	
Coal inventory writedown	**37**	**—**		—					
Share of FFO from joint venture[1]	**3**	**—**		—	—		—	—	
Finance and interest income - economic interests	**—**	**(69)**		—	(76)		—	(171)	
Adjusted FFO - economic interests	**—**	**148**		—	146		—	162	
Other	**15**	**—**		5	—		4	—	
FFO	**685**	**377**	**308**	757	378	379	927	381	546
Dividend from TransAlta Renewables			**151**			151			151
Distributions to TA Cogen's Partner			**(17)**			(37)			(86)
Less: Share of adjusted FFO from joint venture[1]			**(3)**			—			—
Less: PPA Termination Payments			**—**			(56)			(157)
Deconsolidated TransAlta FFO			**439**			437			454

(1) Represents our share of amounts for Skookumchuck, an equity accounted joint venture.

Financial Position

The following table highlights significant changes in the consolidated statements of financial position from Dec. 31, 2019, to Dec. 31, 2020:

Assets	Dec. 31, 2020	Dec. 31, 2019	Increase (decrease)
Cash and cash equivalents	**703**	411	292
Restricted cash	**71**	32	39
Trade and other receivables	**583**	462	121
Risk management assets (current and long-term)	**692**	806	(114)
Assets held for sale	**105**	—	105
Investments	**100**	—	100
Finance lease receivables (long-term)	**228**	176	52
Property, plant and equipment, net	**5,822**	6,207	(385)
Deferred income tax assets	**51**	18	33
Others(1)	**1,392**	1,396	(4)
Total assets	**9,747**	9,508	**239**
Liabilities and equity			
Accounts payable and accrued liabilities	**599**	413	186
Credit facilities, long-term debt and lease liabilities (current and long-term)	**3,361**	3,212	149
Exchangeable securities	**730**	326	404
Decommissioning and other provisions (current and long-term)	**673**	546	127
Risk management liabilities (current and long-term)	**162**	110	52
Deferred income tax liabilities	**396**	472	(76)
Equity attributable to shareholders	**2,352**	2,961	(609)
Others(2)	**1,474**	1,468	6
Total liabilities and equity	**9,747**	9,508	**239**

(1) Includes prepaid expenses, inventory, right-of-use assets, intangible assets, goodwill and other assets.
(2) Includes income taxes payable, dividends payable, contract liabilities, defined benefit obligation and other long-term liabilities and non-controlling interests.

Significant changes in TransAlta's consolidated statements of financial position were as follows:

- See the cash flow section of this MD&A for details on the change in cash during the period.
- Restricted cash increased by $45 million related to the TEC Notes, offset by a reduction in the Big Level and Antrim restricted cash balances.
- Trade and other receivables increased largely due to timing of customer receipts, partially offset by lower collateral payments.
- Risk management assets, net of liabilities, decreased primarily due to contract settlements and changes in market prices and foreign exchange rates.
- Assets held for sale relate primarily to the future sale of the Pioneer Pipeline.
- Investments increased due to the acquisition of Skookumchuck and EMG during the fourth quarter of 2020.
- Finance lease receivables increased in the year with the execution of the BHP Nickle West contract extension.
- PP&E decreased due to depreciation ($717 million), the reclass of pipeline and certain mining equipment to assets held for sale ($105 million), the reclass of the Southern Cross facility to finance lease receivables ($69 million) and asset impairments ($81 million). This was partially offset by additions ($486 million) relating to assets under construction for the conversion to gas, the Windrise wind facility, WindCharger battery storage project, the Kaybob cogeneration project, land and planned major maintenance expenditures. In addition, there were net revisions for increasing decommissioning provisions as a result of changes in cash flows and discount rates ($94 million).
- Deferred income tax assets increased mainly due to lower earnings in Canada compared to the same period last year.
- Accounts payable and accrued liabilities increased largely due to timing of payments for operational payables.
- Credit facilities, long-term debt and lease liabilities increased due to TEC Notes issued in the fourth quarter 2020. This was partially offset by the repayment of $400 million of debentures, repayment of the credit facility ($106 million) and other scheduled principal payments ($86 million).
- Exchangeable securities increased due to the $400 million invested by Brookfield on Oct. 30, 2020, in exchange for redeemable, retractable first preferred shares as part of the Brookfield Investment.
- Decommissioning and other provisions have increased mainly due to revisions in estimated cash flows ($72 million), changes in discount rates ($36 million), liabilities incurred ($35 million) and accretion ($30 million), which was partially offset by liabilities settled ($37 million).
- Equity attributable to shareholders decreased mainly due to net losses for the period ($287 million), common and preferred share dividend payments ($107 million), net losses on cash flow hedges ($91 million), fair value investments losses ($50 million), actuarial losses on defined benefit plans ($11 million) and the share repurchases under the NCIB ($61 million).

Cash Flows

The following chart highlights significant changes in the consolidated statements of cash flows for the years ended Dec. 31, 2020, Dec. 31, 2019, and Dec. 31, 2018:

Year ended Dec. 31	**2020**	2019	**Increase/ (decrease)**
Cash and cash equivalents, beginning of year	**411**	89	322
Provided by (used in):			
Operating activities	**702**	849	(147)
Investing activities	**(687)**	(512)	(175)
Financing activities	**272**	(14)	286
Translation of foreign currency cash	**5**	(1)	6
Cash and cash equivalents, end of year	**703**	411	292

Year ended Dec. 31	2019	2018	Increase/ (decrease)
Cash and cash equivalents, beginning of year	89	314	(225)
Provided by (used in):			
Operating activities	849	820	29
Investing activities	(512)	(394)	(118)
Financing activities	(14)	(651)	637
Translation of foreign currency cash	(1)	—	(1)
Cash and cash equivalents, end of year	411	89	322

Cash provided by operating activities for the year ended Dec. 31, 2020, was lower compared with 2019 primarily due to lower revenues in 2020.

Cash used in investing activities for the year ended Dec. 31, 2020, increased compared with 2019, largely due to:

- Increase due to the investments in Skookumchuck and EMG ($102 million);
- Changes in our restricted cash ($73 million), increased cash spent on construction activities ($69 million) and higher non-cash working capital related to the timing of construction payables for the assets under construction ($54 million); and
- Offset by lower cash spent on acquisitions (TransAlta acquired Ada for $32 million in 2020, compared with the Kineticor acquisition of $87 million and the Pioneer Pipeline acquisition of $83 million in 2019).

Cash from financing activities for the year ended Dec. 31, 2020, increased compared with 2019, largely due to:

- Issuance of long-term debt ($753 million) in 2020 and the exchangeable securities of $400 million; and
- Higher debt repayments ($380 million) as a result of higher scheduled principal repayments on project debt ($393 million) offset by lower payments on the credit facilities ($13 million).

Financial Capital

The Corporation is focused on maintaining a strong balance sheet and financial position to ensure access to sufficient financial capital. 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 provide TransAlta with better access to capital markets through commodity and credit cycles.

During 2020, Moody's reaffirmed its issuer rating of Ba1 with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of 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	2020		2019		2018	
	$	%	$	%	$	%
TransAlta Corporation						
Recourse debt - CAD debentures	**249**	**3**	647	9	647	9
Recourse debt - US senior notes	**886**	**13**	905	13	943	13
Exchangeable securities[1]	**730**	**11**	326	5	—	—
Credit facilities	**114**	**2**	—	—	174	2
Other	**7**	**—**	9	—	11	—
Less: cash and cash equivalents	**(121)**	**(2)**	(348)	(5)	(16)	—
Less: 50 per cent of exchangeable preferred shares[1]	**(200)**	**(3)**	—	—	—	—
Less: principal portion of restricted cash on TransAlta OCP	**(11)**	**—**	(10)	—	(27)	—
Less: fair value asset of economic hedging instruments on debt	**(2)**	**—**	(7)	—	(10)	—
Net recourse debt, excluding US tax equity financing	**1,652**	**24**	1,522	22	1,722	24
Non-recourse debt	**385**	**6**	426	6	469	6
Lease liabilities	**112**	**2**	119	2	63	1
US tax equity financing for TransAlta Renewables economic interests[2]	**134**	**2**	145	2	28	—
Non-recourse debt for TransAlta Renewables economic interests[3]	**782**	**11**	—	—	—	—
Total net debt - TransAlta Corporation	**3,065**	**45**	2,212	32	2,282	31
TransAlta Renewables						
Credit facility	**—**	**—**	220	3	165	2
Less: cash and cash equivalents	**(582)**	**(9)**	(63)	(1)	(73)	(1)
Net recourse debt	**(582)**	**(9)**	157	2	92	1
Non-recourse debt	**670**	**10**	718	10	767	11
Lease liabilities	**22**	**—**	23	—	—	—
Total net debt - TransAlta Renewables	**110**	**1**	898	12	859	12
Total consolidated net debt[4]	**3,175**	**46**	3,110	44	3,141	43
Non-controlling interests	**1,084**	**16**	1,101	15	1,137	16
50 percent of exchangeable preferred securities[1]	**200**	**3**	—	—	—	—
Equity attributable to shareholders						
Common shares	**2,896**	**43**	2,978	42	3,059	42
Preferred shares	**942**	**14**	942	13	942	13
Contributed surplus, deficit and accumulated other comprehensive income	**(1,486)**	**(22)**	(959)	(14)	(1,004)	(14)
Total capital	**6,811**	**100**	7,172	100	7,275	100

(1) Exchangeable preferred securities are considered equity with dividend payments for credit purposes. For accounting purposes, they are accounted for as debt with interest expense in the Consolidated Financial Statements.
(2) TransAlta Renewables has an economic interest in the entities holding these debts.
(3) TransAlta Renewables has an economic interest in the Australia entities, which includes the AU$800 million senior secured notes.
(4) The tax equity financing for Skookumchuck, an equity accounted joint venture, is not represented in these amounts.

We continued strengthening our financial position during 2020 and have sufficient liquidity to fund our growth strategy. We have enhanced shareholder value by:

2020

- Obtaining AU$800 million in project financing related to our South Hedland facility;
- On Oct. 30, 2020, we received the second tranche of $400 million from Brookfield in consideration for redeemable, retractable first preferred shares;
- Redeeming our outstanding 5 per cent $400 million medium-term notes due on Nov. 25, 2020; and
- Purchasing and cancelling 7,352,600 common shares at an average price of $8.33 per share through our NCIB program, for a total cost of $61 million.

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; and
- 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 6.65 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, and
- 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.

Between 2021 and 2023, we have approximately $1 billion of debt maturing, comprised of approximately $631 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We expect to refinance the senior notes maturing in 2022.

The Corporation's credit facilities are summarized in the table below:

		Utilized			
As at Dec. 31, 2020	**Facility size**	**Outstanding letters of credit**(1)	**Actual drawings**	**Available capacity**	**Maturity date**
TransAlta Corporation					
Committed syndicated bank facility(2)	1,250	379	114	757	Q2 2023
Canadian committed bilateral credit facilities(3)	240	150	—	90	Q2 2021 & 2022
TransAlta Renewables					
Committed credit facility(2)	700	92	—	608	Q2 2023
Total	**2,190**	**621**	**114**	**1,455**	

(1) TransAlta has 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, 2020, we provided cash collateral of $49 million.
(2) TransAlta has letters of credit of $89 million and TransAlta Renewables has letters of credit of $92 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.
(3) One of the bilateral $80 million credit facilities has a maturity date of Q2 2021.

The weakening of the US dollar has decreased our long-term debt balances by $24 million as at Dec. 31, 2020. 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	**2020**	2019
Effects of foreign exchange on carrying amounts of US operations (net investment hedge) and finance lease receivable	**(11)**	(21)
Foreign currency cash flow hedges on debt	**(5)**	(9)
Economic hedges and other	**(5)**	(9)
Unhedged	**(3)**	(3)
Total	**(24)**	(42)

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, Kent Hills Wind LP, TEC and TransAlta OCP non-recourse bonds with a carrying value of $1.8 billion (Dec. 31, 2019 - $1.1 billion) 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 third quarter of 2020. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2021. At Dec. 31, 2020, $73 million (Dec. 31, 2019 - $42 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.

Proceeds received from the TEC Notes in the amount of AU$7 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 major maintenance costs.

Working Capital

Including the current portion of long-term debt and lease liabilities, the excess of current assets over current liabilities was $967 million as at Dec. 31, 2020 (2019 - $224 million). Our working capital increased year over year mainly due to repayment of the $400 million debenture in 2020. Excluding the current portion of long-term debt and lease liabilities of $105 million, the excess of current assets over liabilities was $1.1 billion as at Dec. 31, 2020 (2019 - $737 million), an increase of $335 million, mainly due to higher cash and cash equivalents. For further details on changes in cash during the year, please refer to the Cash Flows section of this MD&A.

Share Capital

On March 1, 2021, the Corporation announced that it does not intend to exercise its right to redeem all or any part of the currently outstanding Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares"). The Corporation has provided a notice to the registered shareholders of Series A Shares of the conversion right, on a one-for-one basis, into Series B Shares, and vice versa, providing Series B shareholders the right to exchange Series B Shares, on a one-for-one basis, into Series A Shares. Series A shareholders may elect to retain any or all of their current share holdings and continue to receive a fixed rate quarterly dividend. Series B shareholder may also elect to retain any or all of their current share holdings and continue to receive a floating rate quarterly dividend. After exercising conversion rights, if the balance that remains for either Series A Shares or Series B Shares is less than 1 million, that remaining balance will automatically convert to the other Series. Shareholders' notice of intention to convert must be received by the transfer agent no later than March 16, 2021 and the conversion date will be effective March 31, 2021. The annual dividend rate for the Series A Shares for the five-year period from and including March 31, 2021, to, but excluding, March 31, 2026, will be 2.877 per cent, which is equal to the five-year Government of Canada Bond yield of 0.847 per cent, determined as of March 1, 2021, plus 2.03 per cent. The annual dividend rate for the Series B Shares for the three month floating rate period from and including March 31, 2021, to, but excluding, June 30, 2021, will be 2.103 per cent based on the most recent auction of 90-day Government of Canada Treasury Bills of 0.073 per cent plus 2.03 per cent. The Floating Quarterly Dividend Rate will be reset every quarter.

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	March 2, 2021	Dec. 31, 2020	Dec. 31, 2019
	Number of shares *(millions)*		
Common shares issued and outstanding, end of period	269.9	**269.8**	277.0
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 in equity, end of period	**38.6**	**38.6**	38.6
Series I - Exchangeable Securities(1)	**0.4**	**0.4**	—
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	38.6

(1) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred share are considered debt and disclosed as such in the consolidated financial statements.

Non-Controlling Interests

As of Dec. 31, 2020, we own 60.1 per cent (2019 - 60.4 per cent) of TransAlta Renewables. In 2020, our ownership percent decreased due to TransAlta Renewables issuing approximately 1 million common shares under their Dividend Reinvestment Plan ("DRIP"). We did not participate in this plan.

In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends. The dividend paid on Oct. 30, 2020, to shareholders of record on Oct. 15, 2020, was the last dividend payment eligible for reinvestment by participating shareholders. Subsequent dividends will be paid only in cash.

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 three natural-gas-fired facilities (Ottawa, Windsor and Fort Saskatchewan) and one dual-fuel 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, 2020, decreased by $60 million to $34 million compared to 2019. Earnings were down at TransAlta Renewables in 2020 mainly due to lower finance income and change in the fair value of financial assets an increase in income tax expense, offset by higher operating income and an increase in foreign exchange gains resulting from the strengthening of the Australian dollar relative to the Canadian dollar. Earnings from TA Cogen were lower in 2020 mainly due to lower operating income as a result of the planned outage for the dual-fuel conversion at Sheerness Unit 2, low Alberta market demand and the onerous contract provision for the coal supply agreement (see Note 9 of the consolidated financial statements for further details).

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. The coal-fired generating facility was converted to dual-fuel in 2020.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2020	2019	2018
Interest on debt	**158**	161	184
Interest on exchangeable securities	**34**	20	—
Interest income	**(10)**	(13)	(11)
Capitalized interest	**(8)**	(6)	(2)
Loss on redemption of bonds	**—**	—	24
Interest on lease liabilities	**8**	4	3
Credit facility fees, bank charges and other interest	**18**	15	13
Tax shield on tax equity financing[(1)]	**1**	(35)	—
Interest on the line loss proceeding	**5**	—	—
Other[(2)]	**2**	10	15
Accretion of provisions	**30**	23	24
Net interest expense	**238**	179	250

(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 2020, other interest expense included approximately nil (2019 — $5 million; 2018 — $7 million) 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 higher in 2020 primarily due to interest on the additional $400 million exchangeable preferred shares issued as part of the Brookfield Investment and the AU$800 million TEC Offering, both issued in October 2020. In addition, interest was higher due to interest charges received in 2020 for the AESO transmission line loss proceedings, and the 2019 impact of the $35 million tax credit received relating to the tax shield on Big Level and Antrim projects offset by the termination of the Keephills 3 contract liability in 2019, resulting in the deferred financing costs being recognized.

Net interest expense was lower in 2019 compared to 2018, primarily due to the $35 million credit related to the tax shield 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.

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 2020 and the first quarter of 2021:

	Payable date		Common dividends per share	Preferred Series dividends per share				
Declaration date	**Common shares**	**Preferred shares**		**A**	**B**	**C**	**E**	**G**
Jan. 16, 2020	Apr 1, 2020	Mar. 31, 2020	0.0425	0.16931	0.22949	0.25169	0.32463	0.31175
Apr. 20, 2020	Jul 1, 2020	Jun 30, 2020	0.0425	0.16931	0.22800	0.25169	0.32463	0.31175
Jul 22, 2020	Oct.1, 2020	Sept. 30, 2020	0.0425	0.16931	0.14359	0.25169	0.32463	0.31175
Nov. 3, 2020	Jan. 1, 2021	Dec. 31. 2020	0.0425	0.16931	0.13693	0.25169	0.32463	0.31175
Dec. 23, 2020	Apr. 1, 2021	Mar. 31, 2021	0.0450	0.16931	0.13186	0.25169	0.32463	0.31175

2021 Financial Outlook

The following table outlines our expectation on key financial targets and related assumptions for 2021 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	$960 million - $1,080 million
FCF	$340 million - $440 million
Dividend	$0.18 per share annualized

Range of key power price assumptions

Market	Power prices ($/MWh)
Alberta Spot	$58 - $68
Mid-C Spot (US$)	US$25 - US$35

Other assumptions relevant to the 2021 financial outlook	
Sustaining capital	$175 million - $210 million

Operations

Market Pricing and Hedging Strategy

For 2021, power prices in Alberta are expected to be higher than 2020 with the expiry of the remaining PPAs at six thermal facilities that transferred dispatch control from the Balancing Pool to the asset owners, higher carbon compliance costs, and demand recovery relative to the economy-wide closures from COVID-19 during most of 2020; however, weather and demand are major factors in actual settled prices. Pacific Northwest power prices for 2021 are expected to be comparable to or higher than 2020, but will depend on the actual weather and hydrology of the year. Ontario power prices for 2021 are expected to be higher than 2020 prices if demand recovers from COVID-19 and normal weather is experienced in the province.

The objective of our portfolio management strategy in Alberta is to balance opportunity and risk, and to deliver optimization strategies that contribute to our total investment, which includes a return of and on invested capital. We can be more or less hedged in a given period, and we expect to realize our annual targets through a combination of forward hedging and selling generation into the spot market. The Alberta assets are managed as a portfolio to maximize the overall value of generation and capacity from our hydro, wind and energy storage and thermal facilities. Financial hedging is a key component of cash flow certainty and the hedges are tied to the portfolio of assets rather than a single facility.

Fuel Costs

For the Alberta thermal fleet, we expect the 2021 cash fuel costs per tonne of coal to be higher than 2020 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 thermal facility is in the reclamation stage. Fuel at Centralia has been purchased primarily from external suppliers in the Powder River Basin and delivered by rail. In 2020, we amended our fuel and rail contract such that our rail freight costs fluctuate partly with power prices. The delivered fuel cost in 2021 is expected to be marginally higher than 2020 costs.

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

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

Energy Marketing

EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted and changes in regulation and legislation. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2021 objective for Energy Marketing is for the segment to contribute between $90 million to $110 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 2021 is expected to be higher than in 2020 largely due to higher levels of debt. The increase in debt is mainly due to the AU$800 million TEC Offering and the $400 million exchangeable preferred shares issued as part of the Brookfield Investment, both occurring in October 2020. The increase in debt is offset by repayment of $400 million medium-term notes in November 2020. In addition, changes in interest rates on variable debt, and in the value of the Canadian dollar relative to the US and Australian dollars 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 $2.1 billion in liquidity, including $703 million in cash. We expect to be well positioned to refinance the upcoming debt maturity in 2022. Please 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 2019	Spent in 2020	Expected spend in 2021
Routine capital[1]	Capital required to maintain our existing generating capacity	50	**52**	**44 - 54**
Planned major maintenance	Regularly scheduled major maintenance	68	**98**	**130 - 154**
Mine capital	Capital related to mining equipment and land purchases	23	**7**	**1 - 2**
Total sustaining capital		141	**157**	**175 - 210**
Insurance recoveries of sustaining capital expenditures	Insurance proceeds: 2019 relates to the tower fires at Wyoming Wind and Summerview	(10)	**—**	**— - —**
Total sustaining capital		131	**157**	**175 - 210**
Productivity capital	Projects to improve power production efficiency and corporate improvement initiatives	9	**4**	**3 - 7**
Total sustaining and productivity capital		140	**161**	**178 - 217**

(1) Includes hydro life extension expenditures.

Significant planned major outages at TransAlta's operated units for 2021 include the following:

- Major maintenance turnarounds at Keephills Units 2 and 3;
- 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 2021:

- An outage for major maintenance at Sheerness Unit 1 is in progress with expected completion in the first quarter of 2021. This work will be undertaken in parallel with the conversion to gas of this unit.

Lost production as a result of planned major maintenance, excluding planned major maintenance for Centralia, which is scheduled during a period of dispatch optimization, is estimated as follows for 2021:

	Coal	Gas and renewables	Total
GWh lost	1,600-1,700	550-600	2,150-2,300

Funding of Capital Expenditures

Funding for these planned capital expenditures is expected to be provided by cash flow from operating activities and existing liquidity. In addition, we have access to approximately $2.1 billion, including $703 million in cash, as 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. These costs exclude 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.

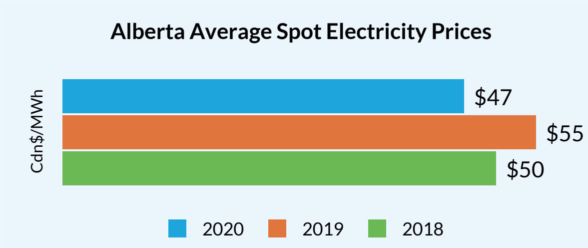
Renewable capacity additions will continue as a result of government policy and evolving corporate stakeholder objectives. New supply in the near term and intermediate term is expected to come primarily from investment in renewable electricity as well as natural-gas-fired generation. This expectation 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 for various terms, up to our available capacity in the markets. We can further reduce the portion of production not sold in advance of the spot markets 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 54 per cent of our gross installed capacity is located in Alberta. Previously, 45 per cent of this was subject to legislated Alberta PPAs, all of which have expired as of Dec. 31, 2020.



Our portfolio of merchant assets in Alberta is a combination of hydro facilities, wind facilities, a battery storage facility and co-fired and converted natural gas-fired thermal facilities. This balance of fuel types provides us with portfolio generation diversification. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. We also enter into financial contracts to reduce our exposure to variable power prices on our merchant generation.

Our Clean Energy Investment Plan, which includes converting our existing Alberta coal facilities to natural gas, will position TransAlta's fleet as a low-cost generator in Alberta. Please refer to the Corporate Strategy section of this MD&A for further details.

Alberta's annual demand contracted approximately 2.5 per cent from 2019 to 2020 due to the combined impacts of COVID-19 and oil production shut-ins. The drop in demand was most significant in the second and third quarters. The average pool price decreased from $55/MWh in 2019 to $47/MWh in 2020. Pool prices were lower in each quarter compared to 2019, with additional weakness during the second quarter as a result of higher power imports into Alberta. Our market share of offer control in Alberta in 2020 was approximately 21 per cent.

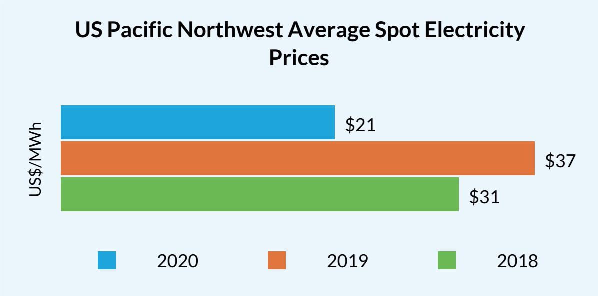
In late November 2016, we announced that we entered into an Off-Coal Agreement with the Government of Alberta that provides transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired facilities on or before Dec. 31, 2030. The Oct. 1, 2019 swap of the Corporation's 50 per cent ownership interest in Genesee 3 for the 50 percent interest in Keephills 3 did not impact the transition payments received under the Off-Coal Agreement. The affected facilities 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 with each province 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 March 31, 2018. As of April 1, 2018, the Sundance facility has been operated as a merchant facility.

US Pacific Northwest

Our capacity in the US Pacific Northwest has been represented by our 1,340 MW Centralia thermal facility. Half of the facility's capacity was retired at the end of 2020 and the other half is scheduled to retire at the end of 2025. 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. We enter into short-term hedges for the remaining generation and can satisfy these or our long-term contract with power purchased from the market during low-priced periods.



Installed capacity in the region is primarily comprised of hydro and gas generation, with substantial wind capacity as well, including our Skookumchuck wind facility, which began production in November 2020. Demand growth in the region has been limited and further constrained by an emphasis on energy efficiency.

We maintain the right to redevelop Centralia as a gas facility 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 cogeneration, we are working with customers to evaluate behind-the-fence solutions.

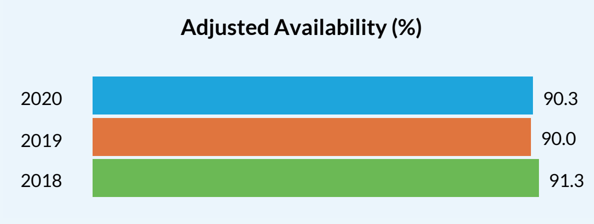
Some of our older gas facilities are now reaching the end of their original contract life. The facilities generally have a substantial cost advantage over new builds and we have been able to add value by recontracting these facilities with limited life extending capital expenditures. We have recently extended the life of our Ottawa (2033 expiry), Windsor (2031 expiry), Parkeston (2026 expiry), Fort Saskatchewan (2030 expiry) and Southern Cross (2038) facilities 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.

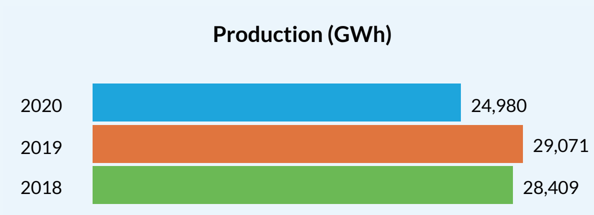
Availability and Production

We achieved 85 per cent (2019 - 89 per cent, 2018 -93 per cent) availability in Alberta Thermal, a decrease from the prior year due to planned outages. North American Gas achieved 97 per cent (2019 - 95 per cent, 2018 - 93 per cent) and Wind and Solar achieved 95 per cent (2019 - 95 per cent, 2018 - 95 per cent). Australian Gas achieved 94 per cent (2019 - 91 per cent, 2018 - 94 per cent), with the increase being the result of unplanned outages in 2019.



Our availability for the entire fleet in 2020, after adjusting for dispatch optimization at Centralia, was 90 per cent (2019 - 90 per cent, 2018 - 91 per cent), consistent with last year. Lower planned and unplanned outages and derates within the generation segments were offset by the planned outages at Alberta Thermal for the Sundance Unit 6 turnaround and conversion to gas outage.

Production for the year ended Dec. 31, 2020, decreased 4,091 GWh compared to 2019. Of the total decrease, 2,822 GWh was primarily due to planned outages, curtailments and dispatch optimization reducing merchant production for Alberta Thermal. In addition, Centralia experienced reduced production of 2,021 GWh due to lower merchant pricing, timing of dispatch optimization, and both Centralia units being taken out of service for the majority of the first half of 2020.



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	2020	2019	2018
Routine capital	**52**	50	50
Mine capital	**7**	23	42
Planned major maintenance	**98**	68	58
Total sustaining capital expenditures	**157**	141	150
Productivity capital	**4**	9	21
Total sustaining and productivity capital expenditures	**161**	150	171
Insurance recoveries of sustaining capital expenditures	**—**	(10)	(7)
Net amount	**161**	140	164

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

Year ended Dec. 31	2020	2019	2018
GWh lost(1)	**980**	935	381

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

Total sustaining capital expenditures were $16 million higher compared to 2019 and total productivity capital was $5 million lower in 2020 compared to 2019. The increased focus on sustaining capital expenditures related to the planned major maintenance at Alberta Thermal for Sundance Unit 6 and conversion to gas outage. In addition, Wind and Solar had sustaining capital expenditures for the Kent Hills foundation work.

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.

2020

Sundance Unit 3

In the third quarter of 2020, the Corporation recognized an impairment charge on Sundance Unit 3 in the amount of $70 million in the Alberta Thermal segment due to the Corporation's decision to retire the unit. Previously, the Corporation had expected Sundance Unit 3 to remain mothballed until November 2021. As there were no estimated future cash flows from power generation expected to be derived from the unit, the unit was removed from the Alberta merchant CGU and immediately written down to the recoverable value of the scrap materials.

BC Hydro Facility

In the third quarter of 2020, the Corporation recorded an impairment of $2 million in the Hydro segment, due to a review of water resources that resulted in a revision to the forecasted production at a BC hydro facility. The impairment assessment was based on fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The resulting fair value measurement is categorized as a Level III fair value measurement. The key assumptions impacting the determination of fair value are electricity production and sales prices, which are subject to measurement uncertainty.

Centralia Land

In the fourth quarter of 2020, the Corporation recognized an impairment of $9 million (US$7 million) in the Centralia segment due to a decrease in the fair value of the land determined through a third-party appraiser. In addition to the asset impairments noted above, a net asset impairment of $3 million was recognized for changes in the decommissioning and restoration liabilities related to the Centralia mine and Sundance Unit 1, which are no longer operating and have reached the end of their useful lives.

2019

Centralia Thermal Facility

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia thermal facility CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia thermal facility CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia thermal facility 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 Centralia 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 ("MOA") for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the facility 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. Please refer to Note 3 and 23 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 Alberta Thermal 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.

Project Development Costs

During 2020, the Corporation wrote off nil (2019 - $18 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, 2020, we provided letters of credit totalling $621 million (2019 - $690 million) and cash collateral of $49 million (2019 - $42 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:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Natural gas, transportation and other contracts	141	149	137	134	134	1,353	**2,048**
Transmission	8	8	8	5	5	1	**35**
Coal supply and mining agreements	81	105	101	67	56	—	**410**
Long-term service agreements	31	37	22	18	10	55	**173**
Operating leases(1)	4	2	2	1	1	26	**36**
Long-term debt(2)	96	626	277	119	136	2,010	**3,264**
Exchangeable securities(3)	—	—	—	—	750	—	**750**
Principal payments on lease liabilities(4)	(5)	6	5	5	5	118	**134**
Interest on long-term debt and lease liabilities(5,6)	161	153	126	119	113	893	**1,565**
Interest on exchangeable securities(3,6)	53	52	53	52	—	—	**210**
Growth	509	411	93	—	—	—	**1,013**
TransAlta Energy Transition Bill	6	6	6	—	—	—	**18**
Total	**1,085**	**1,555**	**830**	**520**	**1,210**	**4,456**	**9,656**

(1) Includes leases that have not yet commenced.
(2) Excludes impact of hedge accounting and derivatives.
(3) Assumes the exchangeable securities will be exchanged by Brookfield on Jan. 1, 2025. Please refer to the Significant and Subsequent Events section of this MD&A for further details.
(4) Lease liabilities include a lease incentive of $13 million, expected to be received in 2021.
(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 MoA, we have committed to fund US$55 million in total over the remaining life of the Centralia thermal facility 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, 2020, the Corporation has funded approximately US$41 million of the commitment.

Contingencies

Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed 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. The AESO submitted a review and variance application of this decision to implement a "pay-as-you-go" invoicing scheme rather than issue a single invoice. The AUC ruled on AESO's request and approved a three-period invoice process (2006-2009, 2010-2013 and 2014-2016). The total liability for the loss charges was $25 million; however, due to payments made (and received) for the first two invoices, only $8 million of the total liability remains outstanding. The AESO issued the first invoice on Oct. 22, 2020, for $6 million, which was paid by Dec. 30, 2020. The second invoice was issued on Dec. 21, 2020, for $11 million. The third invoice is expected in March 2021.

In November 2020, AESO sought direction from the AUC with respect to interest payments on the loss charges, and the AUC ruled in January 2021 that simple interest (rather than compound interest) would apply to the loss charges.

FMG Disputes

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments 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 has been rescheduled to proceed to trial beginning May 3, 2021, instead of June 15, 2020.

The Corporation had a second dispute involving FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claimed certain amounts related to the condition of the facility while TransAlta claimed certain outstanding costs that should be reimbursed. The dispute was settled and discontinued in the Supreme Court of Western Australia on Sept. 9, 2020.

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 of Directors of the Corporation on such date and Brookfield BRP Holdings (Canada), as defendants. Mangrove is seeking to set aside the Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter has been rescheduled and the three-week trial will begin on April 19, 2021.

Keephills 1 Stator Force Majeure Appeal

The Balancing Pool and ENMAX Energy Corporation ("ENMAX") are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal is scheduled to be heard on April 8, 2021. TransAlta believes that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was fair.

Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline March 17, 2015 to May 17, 2015 as a result of a large leak in the secondary superheater. TransAlta Generation Partnership claimed force majeure under the Keephills PPA. ENMAX, the PPA buyer under the PPA at the time, did not dispute the force majeure but the Balancing Pool did, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The Balancing Pool argued and won in the Courts that it has a right under the PPA to commence an arbitration, independent of the PPA buyer, ENMAX. An arbitration for this dispute has commenced and is set to be heard for seven days starting Dec. 6, 2021.

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 Highvale mine. The Balancing Pool and the Utilities Consumer Advocate are participating as interveners because they take issue with the decommissioning costs claimed by TransAlta. Due to various factors, including the COVID-19 pandemic and significant information requests from the Balancing Pool, the application has been delayed. While a hearing date has not been set, the application will likely be heard in late 2021 or early 2022. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

Hydro Power Purchase Arrangement ("Hydro PPA") Emission Performance Credits Credits

The Balancing Pool claims to be entitled to emission performance credits ("EPCs"), valued at approximately $17 million per year, earned by the Hydro facilities under the *Carbon Competitiveness Incentive Regulation* from 2018-2020. 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. An arbitration has commenced and will be likely set down for a hearing sometime in early 2022.

Direct Assigned Capital Deferral Account ("DACDA") Application

AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 DACDA costs (the "Proceeding") incurred for the 240 kV line upgrades project in the Edmonton region (the "Upgrades Project"). TransAlta is a secondary applicant in the Proceeding because it owns a portion of the 1043L Line located on Enoch Cree Nation ("ECN") Reserve that was part of the Upgrades Project. AltaLink and TransAlta sought to have their costs ($91 million for AltaLink and $22 million for TransAlta) approved by the AUC as reasonable and prudent. The ECN and the Consumers Coalition of Alberta are registered participants in the Proceeding. The AUC rendered its decision in the Proceeding on Dec. 10, 2020, and disallowed 15 per cent (approximately $3 million) of TransAlta's portion. TransAlta believes that the AUC made errors by disallowing 15 per cent of its costs and therefore filed a permission to appeal application with the Court of Appeal (the "PTA") and a review and variance application with the AUC (the "R&V"). The PTA will be adjourned until the R&V process is completed.

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

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 facility; 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 when 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 that 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, 2020, is an estimated total upside of $68 million (2019 - $79 million upside) and total downside of $94 million (2019 - $172 million) impact to the carrying value of the financial instruments. Fair values are stressed for volumes and prices. The amount of $35 million upside (2019 - $46 million upside) and $59 million downside (2019 - $139 million downside) in the stress values stems from a long-dated power sale contract in the Pacific Northwest that is designated as a cash flow hedge utilizing assumed power prices ranging from US$24 to US$32/MWh (Dec. 31, 2019 - US$20-US$28/MWh) for the period beyond the liquid period, 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 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 downside of $33 million (2019 - $27 million downside) potential impact to the carrying value of nil as at Dec. 31, 2020 (2019 - nil). 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 one per cent is a reasonably possible change.

Inventory

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. At the end of each reporting period, we assess whether our inventory should be written down to its net realizable value as a result of reduced movement in inventory, lower commodity prices or other events and circumstances that might indicate the cost of the inventory is no longer recoverable.

Determining the amount of the net realizable value requires significant judgment and can vary based on the estimates such as estimated production levels, consumption and sales prices.

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 facility 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 facilities 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 2020.

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 2020 and other specific events, various analyses were completed to assess the significance of possible impairment indicators. Please 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 facility 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 2020, total depreciation and amortization expense was $798 million (2019 - $709 million; 2018 - $710 million), of which $144 million (2019 - $119 million; 2018 - $136 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 2020, 2019 and 2018 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 $345 million (2019 - $454 million) has been recorded on the Consolidated Statements of Financial Position as at Dec. 31, 2020. This primarily relates to income tax deductions in excess of related depreciation of PP&E of $717 million (2019 - $828 million) and taxes on unrealized gains from risk management transactions of $107 million (2019 - $141 million), partially offset by temporary differences related to future decommissioning and restoration costs of $140 million (2019 - $122 million) and net operating loss carryforwards of $222 million (2019 - $252 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, 2020, the decommissioning and restoration provisions recorded on the Consolidated Statements of Financial Position was $608 million (2019 - $501 million). During 2020, the Corporation adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity, including increased volume of material movement. As at Dec. 31, 2020, the decommissioning and restoration provision for Highvale mine was $153 million (2019 - $91 million) for reclamation work anticipated through 2046. The majority of the reclamation work is expected to be complete by 2040. Please refer to the Accounting Changes section of this MD&A for further details. This increase was partially offset by a decrease in the Sarnia decommissioning and restoration provision as a result of an updated engineering study. In addition, due to volatility within the market as a result of COVID-19, we have seen movement within the discount rates as a result of changes in credit spreads. As a result, on average, these rates decreased by approximately 0.3 to 0.9 per cent.

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. As at Dec. 31, 2020, the decommissioning and restoration provision for Centralia mine was $174 million (2019 - $178 million) for reclamation work anticipated through 2035. Please 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 Alberta Thermal and mining operations decommissioning provisions were changed due to the change in useful life.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.4 billion, which will be incurred between 2021 and 2073. The majority of these costs will be incurred between 2025 and 2050.

Sensitivities for the major assumptions are as follows:

Factor	Increase or decrease (%)	Approximate impact on net earnings
Discount rate	1	6
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.

During the fourth quarter of 2020, an onerous contract provision of $29 million was recognized as a result of a decision to accelerate the plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. The last coal shipment is expected to be received during the first quarter of 2021, while payments required under the contract will continue until 2025.

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Corporation must classify it as either a joint operation or joint venture, and the 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

I. Amendments to IAS 1 and IAS 8 *Definition of Material*

The Corporation adopted the amendments to IAS 1 and IAS 8 as of Jan. 1, 2020. The amendments provide a new definition of material that states "information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity."

The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to, the Corporation.

II. Amendments to IFRS 7 and 9 *Interest Rate Benchmark Reform*

In September 2019, the IASB issued amendments to reporting standards relating to *Interest Rate Benchmark Reform* by amending IFRS 9, IAS 39 and IFRS 7. These amendments provide temporary relief during the period of uncertainty from applying specific hedge accounting requirements to hedging relationships directly affected by the ongoing interest rate benchmark reforms. These amendments are mandatory for annual periods beginning on or after Jan. 1, 2020. The Corporation adopted these amendments as of Jan. 1, 2020. There were no hedging relationships that were directly affected on Jan. 1, 2020.

During the first quarter of 2020, the Corporation entered into cash flow hedges of interest rate risk associated with a future forecasted debt issuance using derivative instruments based on the London Interbank Offered Rate ("LIBOR"). As a temporary relief, provided by the IFRS 9 amendments, the Corporation has assumed that the LIBOR interest rate on which the cash flows of the interest rate swaps are based is not altered by interbank offered rates ("IBOR") reform when assessing if the hedge is highly effective.

Note 2 and 3 of the consolidated financial statements include a more detailed discussion of our accounting policies.

Change in Estimates

Alberta Thermal

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. As at Dec. 31, 2020, the carrying value of the Highvale mine, including PP&E, right-of-use assets and intangible assets, was $373 million.

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 conversion 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, 2020, increased by approximately $15 million.

Wind and Solar
During 2019, we reviewed the allocation of the costs recognized for the components of the Wind and Solar PP&E and the useful lives for these identified components. 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 facility 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.

Sarnia
In the fourth quarter of 2020, the Corporation adjusted the Sarnia decommissioning and restoration provision to reflect an updated engineering study. The Corporation's current best estimate of the decommissioning and restoration provision decreased by $15 million. This resulted in a decrease in the related assets in PP&E.

Highvale
In the third quarter of 2020, the Corporation adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity, including increased volume of material movement. The Corporation's current best estimate of the decommissioning and restoration provision increased by $75 million. This resulted in an increase in the related assets in PP&E.

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.

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.

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

Future Accounting Changes

Amendments to IAS 16 *Property, Plant and Equipment: Proceeds before Intended Use*

The Corporation plans to early adopt the Amendments to IAS 16 *Property, Plant and Equipment: Proceeds before Intended Use* on Jan. 1, 2021. The amendment has a mandatory effective date of Jan. 1, 2022. The amendments prohibit deducting from the cost of an item of PP&E any proceeds from selling items produced while bringing the asset to the location and condition necessary for it to be capable of operating. No adjustments are expected from early adopting the amendments.

IFRS 7 *Financial Instruments - Disclosures* - Interest Rate Benchmark Reform

The IASB issued *Interest Rate Benchmark Reform - Phase 2* in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial Instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16: *Leases*. The amendments are effective Jan. 1, 2021, and will be adopted by the Corporation in 2021, no financial impact is expected upon adoption.

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.

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, 2020, Level III instruments had a net asset carrying value of $582 million (2019 - $686 million). Please 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, 2019.

Environment, Social and Governance ("ESG")

Sustainability or ESG management and performance is a priority at TransAlta. Sustainability is one of our core values, which means it is part of our corporate culture. We perpetually strive to further integrate sustainability into our governance, decision-making, risk management and day-to-day business processes, while enabling our growth strategy. The ultimate outcome of our sustainability focus is continuous improvement on key, material ESG issues and ensuring our economic value creation is balanced with a value proposition for the environment and our stakeholders. Over time, we have set ourselves apart with actions that demonstrate ESG leadership:

- We have reported on sustainability for over 25 years, and 2020 reporting marks our sixth year of integrating financial and sustainability disclosure;
- Today, we are proud to be one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta - we have grown our renewable energy capacity from approximately 900 MW in 2000 to over 2,500 MW in 2020;
- Through the period 2002 to 2025 and by way of retirements, gas conversions and expected gas conversions or repowerings, we are on track to transition over 5,000 MW of coal capacity. In 2026, we will be completely off of coal power generation;
- We have reduced our annual emissions by over 25 million tonnes of carbon dioxide equivalent ("CO_2e") since 2005, which is approximately a 61 per cent reduction over the time period and highlights our decarbonization track record: this is the equivalent annual GHG emissions of a small country;
- Our 2030 GHG reduction target supports further reductions and in 2021, we have established a new company-wide target to achieve carbon neutrality by 2050;
- In 2020, CDP (the global disclosure system for environmental impacts known formerly as Carbon Disclosure Project) recognized TransAlta with an A- score, ranking us among industry leaders on climate change management;
- We continue to evolve our leading sustainability target setting process that links targets to sustainability and financial materiality, sets macro targets that are both year-over-year and long term, and involves executive team and Board approval;
- In 2020, TransAlta formed an Equity, Diversity and Inclusion Council and empowered this Council to develop a long-term equity, diversity and inclusion strategy. TransAlta also adopted a Equity, Diversity and Inclusion Pledge unanimously supported by our Board and executive team;
- In 2021, TransAlta was once again added to the Bloomberg Gender-Equality Index — recognition of our focus on equity, diversity and inclusion;
- In 2020, the *Globe and Mail* reported that we moved from a ranking of 48 to a ranking of 14 in their annual "Board Games" report. Board Games assesses the work of Canada's largest boards of directors against a rigorous set of governance criteria (well beyond the minimum set by regulators), covering board composition, compensation, shareholder rights and disclosure. The Board Games are undertaken by the *Globe and Mail* in collaboration with the University of Toronto;
- Our Indigenous youth education target ensures ongoing Indigenous youth education support and, in 2021, we are establishing a new company-wide Indigenous cultural education and awareness target; and
- We participate in and are members of key sustainability organizations and working groups such as the EXCEL Partnership, the Canadian Business for Social Responsibility, the Energy Sector Sustainability Leadership Initiative, Canadian Electricity Association Sustainable Electricity Steering Committee and Future-Fit, which all provide validation and support of our sustainability strategy.

Sustainability Strategy

Our business is electricity. We keep the lights on, our technology charged and critical infrastructure running. We support commercial and industrial customers across three countries. In total, we own 75 power-generating facilities across Australia, Canada and the US. We are invested in a mix of wind, solar, hydro, energy storage, natural gas and coal assets for a total of approximately 8,000 MW of owned generating capacity.

Our key strategic sustainability pillars build on our corporate strategy and weave through our business. Some of these focus areas are already part of our DNA, and our track record in these areas illustrates our commitment to sustainability (including climate change leadership and safety). In other areas where we have set new goals in recent years (including, equity, diversity and inclusion), we believe the focus will only strengthen our corporate strategy and support value creation into the future. Our pillars include:

1. Clean, Reliable and Sustainable Electricity Production
2. Safe, Healthy, Diverse, and Engaged Workplace
3. Positive Indigenous, Stakeholder and Customer Relationships
4. Progressive Environmental Stewardship
5. Technology and Innovation

Sustainability Governance

In order for an organization to truly integrate sustainability, it requires accountability at the Board and executive level. It requires an understanding of ESG issues and associated corporate actions to address these issues, while continuing to balance operations and growth.

Sustainability is overseen by TransAlta's Governance, Safety and Sustainability Committee ("GSSC") of the Board. The GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations, public policy changes and the establishment and adherence to environmental, health and safety practices, procedures and policies. For additional details on our governance, please refer to the Governance and Risk Management section of this MD&A.

Sustainability Reporting: Disclosure Guidance and Materiality

The following outlines material environmental and social considerations in respect of our operated facilities.

Key elements of the following disclosure are guided by our sustainability materiality assessment. Our materiality assessment is developed through evaluation of key sector-specific research on materiality issues and supported by internal and external engagement on key sustainability issues. To provide context on how ESG affects our business (including material focus areas), our content is guided by leading ESG reporting frameworks, including the Global Reporting Initiative ("GRI"), Sustainability Accounting Standards Board ("SASB") and the Task Force on Climate-related Financial Disclosures ("TCFD"). We continue to increase our alignment with SASB and TCFD. Our ESG content is integrated within this MD&A. Content is structured using non-traditional capital (this includes natural, human, social and relationship, intellectual and manufactured capital) as per guidance from the International Integrated Reporting Framework. This approach ensures we inform investors on how management and performance on non-traditional capitals contribute to financial value.

Environmental and Social Risk and Materiality

Our materiality assessment informs our focus on major environmental and social risks. 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 Indigenous and stakeholder relationships.

For further guidance on our risk factors, please refer to the Risk Management section of this MD&A.

Reliable, Low-Cost and Sustainable Energy Production:
Natural, Intellectual and Social Capital Management

Business and Economic Model Resilience

TransAlta has been powering economies and communities for over 109 years. Our mission is to provide safe, low-cost and reliable clean electricity to our customers. To achieve this goal, in today's evolving economy and increasingly electrified world, our strategy focuses on renewable electricity, natural gas and a deep commitment to sustainability. Our business model is primarily focused on providing power to industrial and commercial customers. This model has stood the test of time and we continue to focus our efforts on the customer and adapting to meet customer needs. As customers increasingly adopt ESG and sustainability goals, we are well positioned to support their sustainability objectives. We developed our first sustainability report in 1994. In the early 2000s, we were an early adopter of wind. Our expertise in renewable energy spans 109 years: we began hydro operations in the early 1900s and today we are a leading hydro and wind producer. We believe we are uniquely positioned as the world continues to electrify and adopt sustainability practices.

Brand Recognition

Our business resilience is enhanced by a purpose-based, long-term and sustainable business strategy: growth in renewable electricity and natural gas and a commitment to sustainability. TransAlta has operated power-generation assets for over 109 years, which reflects this approach to long-term and sustainable business practices. A long-term commitment to business and partnerships lends itself to goodwill and brand recognition, something we value and do not 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 positive brand recognition.

Intellectual Capital

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

Diversified Knowledge

The experience and acumen of our employees enhances our value creation. Our experience in developing and operating power-generation technologies extends to over 109 years, and many of our employees have worked with us for over 30 years. Our energy marketing business complements our knowledge of operating power-generation assets.

Our experience in developing and operating power-generation technologies is highlighted below:

Power-Generation Type	Operating Experience (years)
Hydro	109
Natural Gas	70
Coal	70
Wind	18
Solar	5

For further details, please refer to Customers in this section of this MD&A.

Grid Resiliency

As a large electricity generator, we work diligently to ensure the power we provide our customers is reliable, affordable and has low environmental impact. We provide decentralized power solutions to industrial customers and we supply power to centralized power systems.

In all of the jurisdictions where we operate, we work closely with the system operators to ensure overall supply adequacy and reliability of the grid. In Alberta, where we are also a transmission facility owner, we own grid infrastructure that addresses system reliability. We consider a myriad of factors in our planning and operation decisions that could put grid resiliency at risk, including renewable energy intermittency, cyberattacks, extreme weather events and natural disasters.

One solution to support renewable energy intermittency includes investment in battery storage technology. Our first battery storage project began commercial operations in 2020. For more information, please refer to Renewable Energy and Battery Storage in our Natural Capital Management section of this MD&A. For more information on cyberattacks, please refer to Public Health and Safety in the Social and Relationship Capital section of this MD&A. For more information on extreme weather events and natural disasters, please refer to Weather in the Natural Capital Management section of this MD&A.

Customers

TransAlta serves industrial and commercial customers with power and energy services across its fleet in Canada, the US and Australia. As one of the largest electricity generators in Alberta, 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 EPCs; and
- Monitoring of energy market design changes, price signals and applicable and available incentives.

The customer solutions 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.

Across our business in Canada, the US and Australia, we are focused on helping our customers 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 efficient generation of power when compared to other forms of natural gas power generation, and thus can potentially produce EPCs that can be used to satisfy our customers' regulatory obligations or sold for additional revenue.

We provide on-site generation for large mining and industrial customers. This requires us to be continually engaged with these customers ensuring that current electricity requirements are provided safely, reliably and cost-effectively with the benefit of lower GHG emissions.

Another way we contribute to our customers' sustainability goals is through the development of renewable energy and the use of environmental attributes. We continue to develop renewable energy facilities to support customers achieving their sustainability goals and targets, such as 100 per cent renewable power targets and/or GHG reduction targets. Recent examples include our Skookumchuck wind project in Washington, which has a 137 MW capacity and is subject to a PPA with a single offtaker and our Big Level wind project in Pennsylvania, which has a 90 MW capacity and is subject to a PPA with Microsoft Corporation.

We have the ability to generate, trade, purchase and sell: EPCs; Alberta carbon offset credits; 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 or EPCs. EPCs are credits generated by regulated facilities that reduce GHG emissions below their specified reduction targets in the Alberta-based carbon market. 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.

Energy Affordability

TransAlta focuses on assisting commercial and industrial customers in managing their cost of energy. TransAlta has a full suite of procurement strategies and products with various terms available to our customers to assist in understanding and reducing their energy costs.

For customers interested in making a long-term commitment to obtain predictable costs, TransAlta has the experience to develop cogeneration facilities or long-term offtake agreements from its existing and future gas fired and renewable facilities.

End-Use Efficiency and Demand

TransAlta's commercial and industrial customers have access to an extensive set of monthly reports providing detailed tracking of customer usage, allowing for corrective action as required, as well as cost-saving recommendations.

Our Power Factor Report advises the customer of sites that operate at less than a 90 per cent power factor so they can consider installing energy-efficient equipment. By reducing the customer's power system demand charge through power factor correction, the customer's site puts less strain on the electricity grid and reduces its carbon footprint. TransAlta's Site Health Report advises customers of a site whose peak demand has been permanently reduced for a variety of reasons from its initial in-service date. The customer may be paying a higher demand charge each month to the distribution company based on the original peak demand expected at the site. TransAlta collaborates with the customer and determines the new peak demand based on the customer's operation. The customer, working with the distribution company, may find it economic to buy down the distribution contract to reduce the monthly distribution costs going forward.

Progressive Environmental Stewardship: Natural Capital Management

We continue to increase financial value from natural or environmental capital-related business activities, while minimizing our environmental footprint and potential risk factors related to environmental impacts. Comparable EBITDA from renewable energy generation in 2020 was $353 million (2019 - $341 million). Our revenue in 2020 from environmental attribute sales was $25 million (2019 - $28 million). In addition, in 2020 the sale of coal byproducts and waste-related recycling generated financial value in the range of $15 million to $20 million. This is lower than our range reported in 2019 of $25 million to $35 million due to our ongoing transition away from coal-fired generation.

The following are key trends in our natural capital:

Year ended Dec. 31	2020	2019	2018
Renewable energy comparable EBITDA	**353**	341	342
Environmental attribute sales revenue	**25**	28	22
GHG emissions (million tonnes CO_2e)	**16.4**	20.6	20.8

Environmental Strategy

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 provides 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. Since 2002, we have retired over 2,000 MW of coal and converted approximately 420 MW of coal to gas. Our conversion to gas transition is ongoing, and we plan to convert or repower Alberta coal units to natural gas in the 2020 to 2023 timeframe while retiring our Washington State coal facility by the end of 2025. In 2026, our generation mix will be made up of natural gas and renewable energy only.

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 strives 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.

We are 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 damage natural habitat, impact vegetation and wildlife, or cause contamination to land or water that may require remediation under applicable laws and regulations. These laws and regulations require us to obtain and comply with a variety of environmental registrations, licenses, permits and other approvals. The environmental regulations in the jurisdictions in which we operate are robust. Both public officials and private individuals may seek to enforce environmental laws and regulations against the Corporation. We interact with a number of regulators on an ongoing basis, including but not limited to: Alberta Environment and Parks; Ministry of the Environment, Conservation and Parks in Ontario; Ministry of Natural Resources and Forestry in Ontario; Ministry of Forest Lands, Natural Resource Operations and Rural Development in British Colombia; Environment and Climate Change Canada; Fisheries and Oceans Canada; Michigan Department of Environment, Great Lakes, and Energy; Southwest Clean Air Agency in Washington; Washington State Department of Ecology; Washington State Department of Health; US Environmental Protection Agency (EPA); and the Department of Agriculture, Water and the Environment in Australia; and the Clean Energy Regulator in Australia.

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 land use, water use and waste management.

Environmental Governance

The GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Corporation's monitoring of environmental, health and safety regulations, public policy changes, the establishment and adherence to environmental, health and safety practices, procedures and policies in response to legal/regulatory and industry compliance or best practices. The importance of environmental protection is outlined under our Total Safety Management Policy as a corporate responsibility for TransAlta, and the personal responsibility of each employee and contractor working on TransAlta's behalf. This policy is approved by our President and Chief Executive Officer ("CEO").

For more details on governance, please refer to the Governance and Risk Management section of this MD&A.

Environmental Management Systems

All of our 75 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 have a proactive approach to minimizing environmental risks and we anticipate this strategy will benefit our competitive position as stakeholders and society place an increasing emphasis on successful environmental management.

Renewable Energy and Battery Storage

Since 2005, we have added over 1,500 MW in renewable electricity capacity. We operate over 900 MW of hydro energy and our experience with hydro operations spans over 109 years. We were an early adopter of wind energy and today operate 1,500 MW of wind power. 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. In 2020, we commissioned the first utility-scale battery storage project in Alberta, located at our Summerview II wind facility. The project uses Tesla battery technology and has a capacity of 10 MW.

Our production from renewable electricity in 2020 offset the equivalent of approximately 2.9 million tonnes of CO_2e, or the removal of approximately 630,000 cars from North American roads. The estimated GHG offset is calculated using production data (MWh) from each renewable facility multiplied by the regional (provincial or state) grid emissions intensity. This supports our customers in achieving their renewable energy procurement and/or GHG emissions reduction goals. For more details on the types of environmental attributes we generate for customers, please refer to the Customers section of this MD&A.

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 as part of a clean electricity transition. TransAlta operates simple-cycle, combined-cycle, and cogeneration facilities in Canada, the US and Australia. Natural gas facilities provide highly efficient electricity and, in the case of cogeneration, steam production, directly for customers and for the wholesale markets. TransAlta is a significant operator of natural gas electricity in Canada and Australia. We have started converting or repowering Alberta coal units to natural gas. We continue to see a role for natural gas in the future to support system demands and increasing demand for power from customers.

Coal Transition

Our conversion to gas transition plan in Alberta is expected to significantly reduce our environmental footprint. As a result of our coal retirements, conversion to gas and repowerings, our energy use, GHG emissions, air emissions, waste generation and water usage will significantly decline. Transitioning off coal will eliminate all of our mercury emissions, the majority of particulate matter and sulphur dioxide emissions ("SO_2"), as well as significantly reduce our NO_x emissions. The coal retirements eliminate significant GHGs, and the conversion of our Alberta coal facilities to natural gas reduces GHG emissions by 40-60 per cent and supports system reliability, affordability and the growth of renewable electricity in Alberta. Our converted or repowered facilities will also use lower carbon natural gas, compared to facilities in other jurisdictions, as new methane reduction regulations in Alberta and Canada will reduce GHGs in the production and processing phase with respect to flaring and venting of methane (fugitive GHG emissions).

In 2020, TransAlta announced plans to fast-track away from coal mining and coal-fired power generation in Canada by the end of 2021. At our Centralia coal facility in Washington State, one unit was retired in 2020 and the second unit will retire by the end of 2025. In 2022, our coal capacity will be 670 MW, a significant reduction from coal capacity of approximately 5,000 MW in 2015. Coal will be entirely eliminated from our operations by the end of 2025.

Energy Use

TransAlta uses energy in a number of different ways. We burn gas, diesel and coal (to the end of 2021 in Canada and the end of 2025 at Centralia) 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 and create efficiencies related to the use of energy. For 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.

The following table captures our energy use (millions of gigajoules). Energy use declined by 19 per cent in 2020 over 2019, primarily as a result of reduced coal use. Minor revisions were made to our energy use data in 2020 as a result of accrual adjustments from 2019 and 2018. Historical 2019 total energy use was revised from 345 million gigajoules to 346 million gigajoules as a result of these changes. Due to rounding, there was no impact to our reported 2018 total.

Year ended Dec. 31	**2020**	2019	2018
Hydro	—	—	—
Wind & Solar	—	—	—
North American Gas	30	30	28
Australia Gas	21	20	20
Alberta Thermal	135	168	203
Centralia	93	128	107
Corporate and Energy Marketing	—	—	—
Total energy use (million gigajoules)	**279**	**346**	**358**

Air Emissions

Our coal facilities emit 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 reducing air emissions in our existing fleet through our conversion and retirement of coal units in Alberta and Washington State. In 2020, we accelerated our target of 95 per cent SO_2 and 50 per cent NO_x emission reductions over 2005 levels by moving the target date from 2030 to 2026. In addition, we increased the stringency of our reduction levels for NO_x to 80 per cent. Since 2005, we have reduced SO_2 emissions by 83 per cent and NO_x by 68 per cent. We continue to capture 80 per cent of mercury emissions at our coal facilities and, by the end of 2025, mercury emissions will be eliminated following the conversions to gas, Sundance Unit 5 repowering and the retirement of the Centralia facility. 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 thermal 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 thermal facility has two units and we retired one unit in 2020 and will retire the additional unit by 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 trigger 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 2020 decreased compared with 2019 levels. Specifically, NO_x was reduced 19 per cent, particulate matter was reduced 36 per cent and SO_2 was reduced 26 per cent over 2019 levels. Mercury emissions also decreased by 12 per cent over 2019 levels (which is not reflected in the table below due to rounding). Reductions in emissions were largely due to an increase in co-firing (gas and coal) at our Alberta thermal facilities and a reduction in production from our Centralia coal facility. Historical NO_x incurred minor revisions in 2020 to include NO_x emissions from our Highvale mine. The revision increased 2018 NO_x from 28,000 to 29,000 tonnes. There was no change to reported 2019 tonnes as the revision was minor and, with rounding, the volume remains consistent.

The following table represents our material air emissions. Figures have been rounded to the nearest one thousand with the exception of mercury, which are rounded to the nearest ten as totals are considerably lower:

Year ended Dec. 31	**2020**	2019	2018
Sulphur dioxide (tonnes)	**12,000**	16,000	19,000
Nitrogen oxides (tonnes)	**21,000**	26,000	29,000
Particulate matter (tonnes)	**5,000**	8,000	8,000
Mercury (kilograms)	**60**	60	70

Water

Our principal water use is for cooling and steam generation in our coal and gas facilities 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 discharged water. The difference between withdrawal and discharge, representing consumption, is due to several factors, which include 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 2020, we withdrew approximately 240 million m^3 (2019 - 260 million m^3) and returned approximately 200 million m^3 (2019 - 220 million m^3) or 85 per cent. Overall, water consumption was approximately 40 million m^3 (2019 - 40 million m^3). Water withdrawal and consumption was lower in 2020 primarily due to decreased production from our Alberta thermal and Centralia thermal facilities.

Centralia 2019 water data were revised in 2020 as a result of identified discrepancies, which resulted in overreported raw water intake or water withdrawal for sustainability reporting. The issue was specific to 2019 data only. Water from our Centralia facility is also reported to the Department of Ecology ("DOE") in Washington State. There were no issues with our data submitted to the DOE, as the information generated for sustainability reporting followed a separate data collection process. As a result, Centralia 2019 water withdrawal was revised from approximately 52 million m^3 to 26 million m^3. The Centralia business unit has performed a full review of its water reporting process and our corporate function will review its internal assurance process to support avoidance of any future reoccurrence of this event.

Our 2019 company-wide water withdrawal, total water consumption and water intensity were also revised as a result of this change. Overall water withdrawal reduced from approximately 290 million m^3 to 260 million m^3 (result of rounding), total water consumption reduced from 70 million m^3 to 40 million m^3 (result of rounding) and our company-wide water intensity reduced from 2.48 m^3/MWh to 1.55 m^3/MWh.

In 2020, we established a new water consumption reduction target to reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent in 2026 over a 2015 baseline. Water consumption in 2015 was 45 million m^3. This target is in line with the UN's Sustainable Development Goals ("SDGs"), specifically "Goal 6: Clean Water and Sanitation." Our water consumption will fluctuate somewhat over the period of 2020-2025 as we transition off coal, convert and repower gas facilities and ramp production upwards.

The following represents our total water consumption (million m^3) over the last three years. Figures below have been rounded to the nearest 10 million m^3:

Year ended Dec. 31	**2020**	2019	2018
Water withdrawal	**240**	260	250
Water discharge	**200**	220	210
Total water consumption (million m^3)	**40**	40	40

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. 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 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, our customers have developed conservation and re-use strategies aimed at recycling water for mining operational needs. All water used in the region is sourced from scheme water, and with respect to gas and diesel turbine water use, water wash techniques and frequency of activities are continually modified to minimize consumption and environmental impact. Water used in our operations is returned to our customers, who repurpose this water for vegetation and dust suppression in their mining operations.

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 category 4 cyclone event in the area and associated flooding in the region in 2019, 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 facility management.

In southern Alberta, our hydroelectric facilities have played an increasingly important water management role following the flood of 2013. 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.

Waste

The importance of environmental protection and managing waste is outlined in our Total Safety Management Policy as a corporate responsibility for TransAlta, and a responsibility of each employee and contractor working on TransAlta's behalf. Our waste data is reported annually to a number of different regulatory bodies.

In 2020, our operations generated approximately 1.1 million tonnes equivalent of waste (2019 - 1.5 million tonnes). Of total waste generated, 98 per cent was non-hazardous waste and two per cent was hazardous waste. In 2020, only 0.1 per cent of total waste generated was directed to landfill. From the remaining 99.9 per cent, 45 per cent was returned to the mine (ash from coal combustion), 47 per cent was reused or sold to third parties, three per cent was recycled and five per cent was stored.

In 2020, we established a new waste reduction target that by 2022 TransAlta will reduce total waste generation by 80 per cent over a 2019 baseline of 1.5 million tonnes equivalent of waste generation. This is in line with the UN's SDGs, specifically, "Goal 12: Responsible Consumption and Production."

Our reuse waste or byproduct waste is generally sold to third parties. Byproduct sales and associated annual revenue generation typically ranges from $15 million to $20 million. Our operating teams are diligent at not only minimizing waste, but also maximizing recoverable value from waste. 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.

Given our transition off coal, we will no longer produce fly ash waste in Canada past the end of 2021 and past the end of 2025 in the US. The Corporation is looking at recovering fly ash that was returned to its original source at Highvale mine to replace this supply, which is used extensively in the concrete industry. By turning the recovered product into something marketable, it will continue to aid in reducing the amount of cement produced and consequent emissions while offering new job and economic growth opportunities. This innovative technology contributes to a circular economy and will reduce reclamation liabilities for TransAlta.

Biodiversity

The importance of environmental protection and biodiversity is outlined in our Total Safety Management Policy as a corporate responsibility for TransAlta, and a responsibility of each employee and contractor working on TransAlta's behalf. We consider the biodiversity impact at all of our existing operations (with greater focus being given to mining operations) and the biodiversity impacts of all new growth projects are evaluated in line with regulatory compliance and with respect to TransAlta's focus on biodiversity, which is to support biodiversity health.

Growth

Each new TransAlta development project must complete an in-depth environmental assessment (as prescribed by the local regulation and in line with our own assessment practices) describing baseline environmental conditions, identifying potential effects and developing mitigation for identified environmental sensitivities prior to construction and operation. These assessments have been specifically designed to meet the environmental information requirements of the respective regions in which we operate while identifying alignment with the intent of the standards and/or regulations applicable to these jurisdictions (e.g., Wildlife Directive for Alberta Wind Energy Projects, US Fish & Wildlife Service Land-Based Wind Energy Guidelines, etc.). Typically, our renewable projects are greenfield development projects that require a higher level of evaluation compared to a number of our gas projects, which integrate into existing industrial facilities.

In addition, TransAlta provides a detailed wildlife mitigation plan to environmental regulators outlining specific measures that will be employed to mitigate the effects that project construction and operation activities may have on wildlife, wildlife habitat and specific wildlife features identified during environmental studies completed during the development stage.

Each greenfield development project has a detailed stakeholder consultation plan designed to ensure all potentially impacted host landowners, stakeholders, agencies, businesses, non-governmental organizations ("NGOs"), environmental NGOs and Indigenous communities understand the nature of the projects, have multiple and varied opportunities for engagement and feedback, and are able to engage in meaningful dialogue and discussion with TransAlta and its representatives. The ultimate goal is addressing, solving and mitigating stakeholder or Indigenous community biodiversity concerns before filing major permit applications for all of our projects.

Day-to-Day Operations

At our Alberta thermal operations, we have a Wildlife Monitoring Program designed to monitor wildlife abundance and species diversity in the study area over time. Based on these surveys, TransAlta has seen primarily stable or increasing biodiversity in the area, with various new bird species being detected over the years and incidents of vehicle collisions decreasing due to lower speed limit restrictions. Some animal population sizes fluctuate in the area based on weather conditions and available ground cover.

Our natural gas operations have a relatively limited impact on biodiversity. The facilities are frequently constructed adjacent to existing industrial operations, and TransAlta may not always be the holder of the environmental permits. The land area these facilities occupy is also generally relatively small. One exception is our Sarnia cogeneration facility. This facility is made up of 260 acres of brownfield industrial land, some of which contains areas with tall grasses and potential wildlife. Care will be taken at the time of redevelopment of this land to minimize impact to species at risk through the completion of species-at-risk surveys as well as performing certain construction activities outside of nesting periods. For all sites that are under our environmental scope, we adhere to all relevant environmental compliance permits.

At our hydro facilities, a major focus is on reducing the impact on fish and fish habitat. We adhere to provincial and federal regulations and operate in accordance to facility approvals. We continue to work towards operational improvement and regularly review our Environmental Operational Management Plans to ensure our operating parameters are met.

At our wind and solar operations, the business unit has established the WiSPER (Wind Stewardship Planning and Environmental Reporting) Program. The goal of the program is to provide continuous improvement and ongoing environmental monitoring programs beyond TransAlta's regulatory requirements. This is achieved through periodic audit and inspection programs, and through collaboration with industry and the scientific community to address environmental concerns and impacts. An Operational Environmental Management Plan has been developed for each renewable asset to ensure that our facilities use environmentally sound and responsible practices that are based on a philosophy of continuous improvement of environmental protection through a program of inspection, monitoring and review.

Examples of WiSPER initiatives to support our biodiversity focus include our Avian Protection Program (installation of covers to protect birds from possible electrocution), a bird and bat mortality database (records all injuries and mortalities), environmentally sensitive resource monitoring (monitoring sensitive wildlife features in and around our operating wind facilities such as raptor nests and sharp-tailed grouse leks), long-term dataset collections (e.g., wildlife studies pre-construction and post-construction) and community wind education programs.

For further details on our environmental strategy, please refer to the Environmental Incidents and Spills discussion and the Land Use discussion of this MD&A.

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. The Highvale mine will close at the end of 2021 as part of discontinuing coal-fired power generation in Canada at the end of 2021. In 2020, our reclamation team updated our mine reclamation plans. The updated plans align with community priorities for the reclaimed land. These reclamation plans were submitted to the regulator and we are seeking approval on these plans. The regulator timeline for approval can be anywhere from one to three years. 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. Associated with our plans, we have recently announced a target to have the Highvale mine fully reclaimed by 2046.

In 2020, the Centralia mine planted 81,000 Douglas Fir trees on land that was reclaimed in previous years. However, further reclamation work at our Centralia was paused in 2020 due to the COVID-19 pandemic. At our Highvale mine, approximately 25 acres (10 hectares) were reclaimed in 2020.

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.

Incidents and Spills

Protecting and minimizing our impact on 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 to ensure we can accurately evaluate the level of significance to biodiversity following an incident. We closely monitor the air, land, water and wildlife in these areas to identify and curtail potential impacts.

In 2020, environmental incidents were separated into two categories: significant environmental incidents and regulatory non-compliance environmental incidents. We define regulatory non-compliance environmental incidents as events involving a non-compliance event that 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 if there is some level of impact to the environment. In 2020, we recorded six significant environmental incidents (2019 - three incidents). Our six significant environmental incidents (all bird and bat strikes — further details below) will not cause any long-term impacts on the environment and the associated ecosystem and did not trigger any enforcement action. The Corporation is working to ensure our classification is accurate as a true significant environmental incident is one that causes harm to the environment and poses a long-term impact on a local ecosystem. In 2020 we note that we did not experience an incident with such an impact. We recorded two regulatory non-compliance environmental incidents in 2020 (2019 – six incidents). Both of these incidents occurred at our Sarnia facility and were related to an exceedance of discharge from our sumps during water treatment. Both incidents had negligible environmental impact.

Our six significant environmental incidents in 2020 occurred at our Summerview (Alberta), Antrim (New Hampshire) and Big Level (Pennsylvania) wind facilities. Four New Hampshire state-listed bat carcasses were found during the post-construction biological survey in Antrim (three little brown bats and one eastern small-footed bat). One Pennsylvania state-listed bird (yellow-bellied flycatcher) was found during the post-construction biological survey at Big Level. A ferruginous hawk, a listed species in Alberta, was found during an ongoing inspection during normal operation. In each case, root cause analysis investigations were performed, and we found no causal factors or root causes related to human behaviour or equipment failure being involved in the incidents. For all incidents, we collaborated with authorities and there were no enforcement actions with respect to the mortalities. Despite inconclusive findings, smart bat curtailment optimization is contemplated in Antrim and the biological monitoring studies continues at relevant sites.

Significant environmental incidents by business segment follow:

Year ended Dec. 31	2020	2019	2018
Hydro	—	—	—
Wind & Solar	6	3	—
North American Gas	—	—	—
Australia Gas	—	—	—
Alberta Thermal	—	—	1
Centralia	—	—	—
Corporate and Energy Marketing	—	—	—
Total significant environmental incidents	**6**	**3**	**1**

Regulatory non-compliance environmental incidents by business segment follow:

Year ended Dec. 31	2020	2019	2018
Hydro	—	—	—
Wind & Solar	—	1	—
North American Gas	2	2	2
Australia Gas	—	—	—
Alberta Thermal	—	2	2
Centralia	—	1	2
Corporate and Energy Marketing	—	—	—
Total regulatory non-compliance environmental incidents	**2**	**6**	**6**

Some examples of mitigation measures TransAlta has taken include:

- Installation of artificial nest platforms to increase breeding opportunities for endangered ferruginous hawks in southern Alberta;
- Installation of bluebird nest boxes to increase breeding habitat for this sensitive species found at some of our southern Alberta wind facilities;
- Bobolink Management Plan at the Wolfe Island wind facility – creation of 50 acres of breeding habitat for bobolink (a sensitive bird species in Ontario) to offset the potential impacts of the Wolfe Island wind facility on this species; and
- Implementing operational bat curtailment at the Antrim, Big Level, Summerview and Kent Breeze wind facilities during the fall bat migration period (July to September) to reduce bat mortality at these sites by increasing the cut-in speed.

For 2021, we are removing our target for environmental incidents. This is because we do not tend to experience environmental incidents that have a large or lasting impact on the environment and an ecosystem, and we believe it is prudent to instead focus on other environmental areas that are more material for the Corporation. This will not change our internal focus on mitigation of environmental incidents. We continue to track and manage all environmental incidents, including 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.

Regarding spills and releases, typical spills that could occur at our operation sites are hydrocarbon-based. Spills generally happen in low environmental impact areas and are almost always contained and fully recovered. It is extremely rare for large spills to occur. Efforts are placed on providing a quick response to all spills to ensure assessment, containment and recovery of spilled materials result in minimal risk to the environment.

There is a potential that ash ponds associated with our coal facilities could fail. The probability of this occurring is low, but the impact could be significant. We follow applicable environmental regulations with respect to our ash ponds and satisfy ourselves that management is adequate given the robust regulations in the jurisdictions where we operate. Management includes periodic inspections and appropriate mitigation if issues are uncovered. An inspection in 2020 noted cracks in one of our ponds. In response, a restoration plan was developed to fix the issue. The total cost of mitigation was $1 million.

The estimated volume of spills in 2020 was 4 m^3 (2019 - 530 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.

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 facility. 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. Accumulated ice 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. 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. Please refer to the Governance and Risk Management section of this MD&A for further discussion on weather-related risks.

During the past three years, we have experienced no significant impacts to annual financial results due to deviations from expected weather patterns.

Progressive Environmental Stewardship: Climate Change Management

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 TCFD recommendations. The following highlights our management, performance and leadership of impacts related to climate change.

TransAlta Climate Change Action - Highlights

- 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 a 100 per cent mix of renewables and natural gas by the end of 2025;
- Our business is showing resilience to mitigation of global warming by reducing GHG emissions — we have a target to reduce annual emissions by 19.7 million tonnes of CO_2e by 2030 over 2015 levels and a new goal to be carbon neutral by 2050. Since 2015, we have reduced our annual emissions by 15.8 million tonnes of CO_2e or approximately 80 per cent of required GHG reductions to meet this target;
- We have reduced our annual emissions by approximately 25 million tonnes of CO_2e since 2005, which is a 61 per cent reduction over the time period and highlights our decarbonization track record - this is the equivalent annual GHG emissions of a small country;
- As a leader in North American renewable energy, and on-site generation development and production, we are well positioned to build renewable energy facilities and lower-carbon gas facilities to support customer sustainability goals to decarbonize; and
- In 2020, CDP (the global disclosure system for environmental impacts known formerly as Carbon Disclosure Project) recognized TransAlta with an A- score, ranking the Corporation among industry leaders on climate change management.

Climate Change Governance

The highest level of oversight on business impacts related to climate change 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. These deliberations resulted in our actions to move away from coal, establish 2030 and 2050 GHG emissions reduction targets and grow our generation capacity with renewable energy and gas.

The GSSC has oversight of climate-related issues. Meeting on a quarterly basis, the GSSC's charter includes "monitoring and assessing climate change risks and compliance with associated legislation and public reporting." The charter also directs that the GSSC "at least annually, review guidelines and practices relating to environmental protection, including the mitigation of pollution and climate change; consider whether TransAlta's policies and practices relating to the environment are being effectively implemented, and discuss and advise regarding the development of policies and practices regarding climate change, greenhouse gas and other pollutants."

In addition to the GSSC, climate risks are reviewed through the AFRC. For example, climate policy considerations are factored into decision-making with respect to conversion of coal facilities to gas facilities. In addition, many of our new projects, including clean energy projects, are reviewed by other committees of the Board and climate risk and opportunity is factored into those committee deliberations. As a result, climate change related capital expenditures, acquisitions and budgets are also reviewed at the Board level on a case-by-case basis.

Notably, five of our Board members have identified Environment and Climate Change as being among their top four relevant competencies. We have noted this in our skills matrix section of our 2020 Management Proxy Circular on page 33.

The highest level of oversight on climate change at our executive level is with the President and CEO. Climate change related risks are monitored and actively managed through our TransAlta-wide risk management processes. Climate change risks and opportunities are identified and reviewed at the Board level and all levels of the Corporation. The business units and corporate functions work closely together and flow risks and opportunities upwards to the executive and the Board. Risks and opportunities are reviewed by our CEO and executive team quarterly and are reported to the GSSC and the AFRC.

A significant component of executive compensation is tied to achieving our strategic goals, which include growing renewable energy, reducing GHG emissions through our conversion to gas transition and supporting our customer sustainability goals to decarbonize through on-site low carbon generation. Our corporate executive annual incentive plans (short-term incentive or annual bonus and long-term share incentives) are linked to TransAlta's performance (i.e., "pay for performance"). These incentives are linked to execution of strategic goals and our compensation philosophy is designed to drive the right actions to achieve our strategic goals. The long-term incentive plan for the period 2018 to 2020 included a strategic goal to Transition to Renewable Energy. This goal was measured against the performance of the Corporation, which included: advancing and executing our conversion to gas (which results in significant GHG reductions); deliver growth in our renewables fleet (zero or very low carbon assets); expand our presence in the US renewables market (zero or very low carbon assets); advance and grow our on-site generation and cogeneration business (decentralized and low carbon/high energy-efficiency assets); continue to improve our already strong financial position; and remain disciplined with our capital investment strategy. As such, our incentive program is tied to reducing GHG emissions and climate change management.

Climate Change Strategy

TransAlta, and the electricity sector in general, are at the forefront of reducing GHG emissions, pursuing innovative lower-carbon and zero-carbon solutions (e.g., renewable energy, natural gas, distributed power generation, energy storage, etc.) and are showing a path to resiliency in a low-carbon world. Our investments and growth in renewable energy are highlighted by our diverse portfolio of renewable energy-generating assets. We currently operate approximately 2,500 MW of hydro, wind and solar power. In 2020, we completed construction and commercial operation of an additional 136 MW (net 67 MW) of wind generation in the US (2019 - 119 MW). 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.

In addition to climate resiliency, TransAlta remains focused on 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. In 2021, we have adopted a target to be carbon neutral by 2050. We believe carbon neutrality provides flexibility as we shape our strategy over the coming decades and we believe our clean electricity strategy has us well positioned to support us achieving this.

In 2021, we are conducting scenario analysis to further inform our understanding of risks, opportunities, technologies and pathways with respect to a number of future climate scenarios. This process will help inform us as we evaluate strategic GHG reduction pathways with respect to achieving our target of carbon neutrality by 2050. This target aligns us with efforts in the countries where we operate and broader global efforts under the Paris Agreement.

All 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 footprint.

With respect to our customers, we note that we are shifting our product offering from a GHG-intensive product to a low-carbon product to meet the need to decarbonize and mitigate associated societal risks, but also to meet the changing goals of our customers. We continue to build renewable projects for customers seeking to meet their own sustainability goals, such as carbon neutrality on Scope 2, RE100 goals or net zero. We continue to support customers with on-site power-generation goals, where collectively there is an opportunity to reduce GHG impacts through on-site cogeneration, where power and steam production replace existing higher GHG-intensive boilers. Our conversion of coal facilities to gas will significantly reduce the GHG intensity of the Alberta grid, supporting Scope 2 emission reductions for our customers and Alberta commercial and industrial loads.

Another way we can contribute to our customers' sustainability goals is through the use of environmental attributes. We have the ability to generate, trade, purchase and sell environmental attributes that include Alberta EPCs, Alberta carbon offsets, RECs and emission offsets. Production from renewable electricity in 2020 resulted in avoidance of approximately 2.9 million tonnes of CO_2e for our customers, which is equivalent to removing over 630,000 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 from renewable energy. Annual revenue generation from the sale of environmental attributes (Alberta carbon offsets and RECs) in 2020 was $25 million.

Climate Change Risk Management

Climate change risks are monitored and actively managed through our TransAlta-wide risk management processes. Although we do not have a formal process to review specific climate change risk, 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 units and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board. One area that is constantly monitored is climate policy, including the impacts on cost, growth and compliance.

Climate change risks at the asset or business unit level are identified through our EMS, 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. All identified material risks are added to our Enterprise Risk Management risk register. These risks are assessed and scored based on likelihood and impact (what could have "substantive financial impact," "strategic impact," "stakeholder or reputational impact" or "environment, health and safety impact"). Risks are not considered in isolation. Major risks are the focus of management response and mitigation plans.

Our climate change risks are divided into two major categories as per guidance from the TCFD, which include: (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 to a Lower-Carbon Economy

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, please refer to the Governance and Risk Management section of this MD&A.

Canadian Federal Government

Federal Climate Plan

On Dec. 11, 2020, the Government of Canada released its "*A Healthy Environment and a Healthy Economy*" climate plan that outlines how the federal government intends to use policies, regulations and funding to achieve Canada's Paris Agreement emission reduction target of 30 per cent reduction from 2005 greenhouse gas emission levels. The three major aspects of the plan include increased carbon prices and obligations, increased funding for clean technology and the implementation of the Clean Fuel Regulation ("CFR"). The government stated that it will consult with provinces and industry regarding many elements of the plan so significant uncertainty remains regarding the final form of the related regulations and other initiatives.

Key proposed elements of the federal plan:

- Carbon price for the carbon tax and the larger emitters program is to rise $15 per tonne CO_2e per year from 2023 until reaching $170 per tonne by 2030;
- Carbon obligations to rise as performance standards (benchmarks) under large emitter regulations tighten;
- Over $10 billion of funding will be made available for the energy transition, including support for electric vehicles and clean energy development to battery storage and improved grid technology; and
- Implementation of the CFR on liquid fuels, but no CFR obligations for gaseous and solid fuels.

TransAlta intends to continue to engage with governments to mitigate risks and identify opportunities within the new federal plan.

Clean Fuel Regulation

In 2016, the Canadian federal government announced plans to consult on the development of a CFR to reduce Canada's GHGs 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.

On Dec. 19, 2020, the Canadian federal government published its draft version of the CFR with the accompanying supporting documents. As a result of gaseous fuels no longer being regulated by the CFR, the CFR will have a limited impact on the electricity sector. Consultation on the regulation will conclude on March 4, 2021. The CFR is scheduled to be finalized in December 2021 and come into force on Dec. 1, 2022.

Federal Carbon Pricing on GHGs
On June 21, 2018, the Canadian federal *Greenhouse Gas Pollution Pricing Act* ("GGPPA") came into force. Under the GGPPA, the federal government implemented a national price on GHG emissions. 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. 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.

As noted above, in the *"Healthy Environment and a Healthy Economy"* plan, the federal government proposed escalating the national price on carbon by $15 per tonne each year from 2023 until it reaches $170 per tonne in 2030.

The OBPS regulates large emitters' carbon intensity by setting a sectoral 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 EPCs. Emitters can meet their obligations by reducing their emission intensity, buying carbon credits from others (offsets or EPCs) or making compliance payments to the government.

As discussed in the provincial sections below, the OBPS does not apply in Alberta and Ontario is in the process of transitioning out of the OBPS and into a provincial industrial carbon pricing system. As a result, TransAlta's Canadian thermal fleet will be regulated by provincial systems moving forward. However, the federal government compares provincial carbon pricing systems against the OBPS when deciding whether provinces have achieved equivalency with the federal government's carbon price under the GGPPA. On Feb. 12, 2021, the federal government began planning for a 2022 review of the OBPS and other aspects of the GGPPA. TransAlta will actively engage in this process as any changes to the OBPS will influence provincial carbon pricing systems in the future.

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/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, conversions to gas 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.

As part of the *Healthy Environment and a Healthy Economy Plan*, the federal government signalled an interest in exploring a new emissions performance standard for the Canadian electricity sector. There are few details available regarding the potential new standard and TransAlta is engaging the federal government to understand the intent of the proposal.

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.

Alberta

Large Emitter Greenhouse Gas Regulations

On Jan. 1, 2020, the Government of Alberta replaced the previous Carbon Competitiveness Incentive Regulation ("CCIR") with a new regulation called the *Technology Innovation and Emissions Reduction* ("TIER") Regulation. For the electricity sector, there were negligible changes between CCIR and TIER with renewable facilities continuing to receive crediting. The carbon price for TIER in 2021 will be $40/tonnes CO_2e aligned with the GGPPA 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 comply with TIER by: a) paying into the TIER Fund (a government-controlled fund that invests in emissions reduction in the province) at the current carbon price; b) making reductions at their facility; c) remitting EPCs from other facilities; or d) remitting emission offset credits.

As required by the GGPPA, the Alberta government files annual reports on TIER program details with the federal government. The federal government reviewed TIER and found it compliant with the GGPPA for 2021. The Corporation will continue to receive offsets and EPCs for its renewable facilities under TIER, ensuring expected revenues are realized.

British Columbia

Beginning April 1, 2018, the British Columbia government increased its carbon tax price to $35 per tonne CO_2e and committed to raise the price $5 per year until it reaches $50 per tonne in 2021. Upon review, the government has determined that the carbon tax rate will remain at its current level of $40 per tonne CO_2e until April 2021, when it will increase from $40 to $45 per tonne CO_2e. The carbon tax will increase to $50 per tonne CO_2e in April 2022. The tax has a negligible cost impact for the Corporation as the tax applies primarily to our transportation fuel use, which is negligible in BC.

Ontario

Large Emitter Greenhouse Gas Regulations

On July 4, 2019, the Government of Ontario released its final regulations for the provincial Greenhouse Gas Emissions Performance Standards ("EPS"). On Sept. 21, 2020, the federal government accepted the Ontario government's EPS as meeting the requirements of the GGPPA. In December 2020, the Ontario government published amendments to align the EPS with the GGPPA requirements. The Ontario government also announced its intention to transition from the OBPS to the EPS starting on Jan. 1, 2021. Therefore, Ontario's large emitters were covered by the OBPS for 2019 and 2020 compliance years and will subsequently be covered by the EPS.

This requires TransAlta's Ontario natural-gas-fired assets to track and make compliance filings annually and to meet the carbon emission obligations of the applicable government. There are minor differences between the EPS and OBPS. Compliance requirements will be met through payments and alternative compliance units under the OBPS and EPS. However, change-of-law provisions in the contracts with Sarnia, Windsor and Ottawa allow TransAlta to flow carbon-regulation-related costs to customers, resulting in negligible cost increases to the Corporation.

Michigan

Michigan has air permit requirements related to the Clean Air Interstate Regulation with respect to NO_x and SO_2 emissions. There are currently no GHG emission compliance requirements other than to report these emissions annually. The Ada cogeneration facility is in compliance with all environment requirements and there have been no recent changes to regulations that would increase costs at the facility.

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 emissions regulatory burden on Centralia 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.

Le Nordais receives value from the sale of RECs into the New England RPS markets. Massachusetts has proposed a lower compliance cost ceiling on its RPS standard that would effectively cap the value of RECs. This could have a negative impact on Le Nordais' REC sales price. The change in regulation is still being considered and has not yet been put into force.

Australia

On Dec. 13, 2014, the Australian government enacted legislation to implement the Emissions Reduction Fund (the "ERF"). The AU$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.

In addition, on June 23, 2015, the federal Australian government also reformed the Renewable Energy Target ("RET") scheme. The RET is designed to add at least 33,000 GWh/year of renewable sources by 2020. The Australian government has advised there are now sufficient projects approved to meet and exceed the 2020 target of 33,000 GWh/year of additional renewable electricity. The annual target will remain at 33,000 gigawatt hours until the scheme ends in 2030. This would result in approximately 23.5 per cent of Australia's electricity generation being sourced from renewable projects.

The ERF is not expected to have a material impact on our Australian assets. In Australia, electricity has a single sectoral baseline applied to all electricity generators' emissions for units connected to one of Australia's five main electricity grids. The electricity sector baseline has been set at 198 million tonnes CO_2e per year. In the most recent high emission years of 2015-2016, total emissions were 179 million tonnes CO_2e per year.

If the baseline is exceeded, then all large emitter generation facilities will need to comply with individual facility baselines. The electricity sector should never exceed the sectoral emission target as no new coal generation is to be built and older coal facilities are retiring. The Corporation's gas facilities will not be subject to carbon costs under current regulations unless changes are made.

Technology Risks

Our conversion to gas strategy uses existing infrastructure and applicable technologies (natural gas turbines), which reduce the cost and GHG emissions related to new generation construction and material procurement.

Behind-the-fence generation and energy storage technology are emerging risks to the large-scale power-generation model. However, they are practical solutions for some customers, and TransAlta provides these technologies in addition to providing services to the grid.

We provide behind-the-fence generation or decentralized power to some of our industrial customers to supply on-site electricity generation. This generally can be in the form of a cogeneration system that provides steam for industrial processes in addition to power, or a renewable power system. These systems can either be tied to the grid or independent.

Battery storage has the ability to enable greater adoption of renewables and motivate 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. TransAlta began commercial operations of Alberta's first utility-scale lithium-ion battery storage facility, called WindCharger, on Oct. 15, 2020. This project is unique as it uses TransAlta's existing Summerview II wind facility to charge the battery, allowing WindCharger to be a truly renewable battery energy storage system. The project uses Tesla technology and the potential exists for the expansion of this technology. We are investigating the viability of battery storage at our various wind facility locations and for use in developing customer-specific energy supply solutions.

We have demonstrated upside in growing renewables and gas-powered generation. From 2000 to 2020, we have grown renewables capacity from approximately 900 MW to over 2,500 MW.

Market Risks

TransAlta has taken significant steps since 2005 to reduce its GHG impact and has announced a full transition off coal by the end of 2025. TransAlta continues to operate hydro facilities and invest in, develop and construct on-site natural gas facilities for customers and new renewable energy from wind, solar, and battery technology.

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 toward electrification of the economy. Our low-carbon business model supports this type of future.

Increased costs for natural gas supply due to carbon pricing can impact our operating costs. 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, remove 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. We are invested in a diversified mix of renewable generation as well as natural gas, as it provides vital support to the electricity system.

2. Physical Impact Risks of Climate Change

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

Acute Risks

We are continuing to evaluate the potential impact of an acute climate change related impact to our business and/or an operational facility or facilities. Our facilities, construction projects and operations are exposed to potential interruption and damage or partial or full loss resulting from environmental disasters (e.g., floods, high winds, fires, ice storms, earthquakes and public health crises, such as pandemics and epidemics). Climate change can increase the frequency and severity of extreme weather events. Further impacts of extreme weather and climate change could result in social unrest, war or terrorism. There can be no assurance that in the event of an earthquake, hurricane, tornado, tsunami, typhoon, or other natural, man-made or technical catastrophe, all or some parts of our generation facilities and infrastructure systems will not be disrupted. The occurrence of a significant event disrupting the ability of our power generation assets to produce or sell power for an extended period, including events that preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on our business.

We seek to mitigate future impact where relevant with climate adaptation solutions. The TransAlta South Hedland facility in Western Australia was built with climate adaptation in mind. The facility is designed to withstand a category 5 cyclone. 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, when a category 4 cyclone hit this facility, operations were not impacted and we were able to continue generating electricity through the storm, despite widespread flooding and the 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.

Climate Change: Metrics and Targets

In 2020, we estimate that 16.4 million tonnes of GHGs with an intensity of 0.67 tonnes per MWh (2019 - 20.6 million tonnes of GHGs with an intensity of 0.75 tonnes per MWh) were emitted as a result of normal operating activities. This reduction of approximately 20 per cent or 4.2 million tonnes CO_2e is primarily the result of co-firing with gas and lower production volumes at our merchant Alberta coal facilities and lower production from our Centralia coal facility. In 2020, our renewable energy facilities also offset approximately 2.9 million tonnes of CO_2e for our customers. Because we sell the environmental attributes (offsets and RECs) generated from our renewable energy facilities, we do not net this amount from our total GHGs, but it should be noted that this offset is occurring and our customers are reporting net GHG reductions from TransAlta's renewable energy operating activities.

Our 2020 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 historical revisions will be captured and reported in future disclosure. 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 result from carbon dioxide emissions from stationary combustion from coal and natural-gas-powered generation. Emissions 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.

Global warming potentials can vary with respect to regional compliance guidance. We compile our corporate GHG inventory using our business segment GHG calculations. The Clean Energy Regulator in Australia amended global warming potentials in August of 2020 and the use of global warming potentials in our Australia Gas GHG calculations differ from the rest of our fleet as a result of these amendments. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.

The GHG Protocol Corporate Accounting and Reporting 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 2020 were estimated to be 16.3 million tonnes CO_2e and accounted 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 and Energy Reporting), Canada (Greenhouse Gas Reporting Program) and the US (EPA). Scope 2 emissions in 2020 were estimated to be 0.1 million tonnes CO_2e. We estimate our Scope 3 emissions in 2020 to be in the range of six million tonnes, which is primarily attributed to our non-operating joint venture interests.

The following are our GHG emissions broken down by business segment, by Scope 1 and 2 and by country in million tonnes CO_2e. In our business segment breakdown Hydro, Wind & Solar, Corporate and Energy Marketing are shown as 0.0 in million tonnes, but do have minor GHG emissions.

Year ended Dec. 31	2020	2019	2018
Hydro	**0.0**	0.0	0.0
Wind & Solar	**0.0**	0.0	0.0
North American Gas	**1.5**	1.5	1.4
Australia Gas	**1.1**	1.0	1.0
Alberta Thermal	**7.9**	10.1	12.3
Centralia	**5.9**	8.0	6.1
Corporate and Energy Marketing	**0.0**	0.0	0.0
Total GHG emissions	**16.4**	**20.6**	**20.8**

Year ended Dec. 31	2020	2019	2018
Scope 1	**16.3**	20.4	20.6
Scope 2	**0.1**	0.2	0.2
Total GHG emissions	**16.4**	**20.6**	**20.8**

Year ended Dec. 31	2020	2019	2018
Australia	**1.1**	1.0	1.0
Canada	**9.4**	11.6	13.7
United States	**5.9**	8.0	6.1
Total GHG emissions	**16.4**	**20.6**	**20.8**

All of our reported 2020 and historical GHG emissions are verified by Ernst & Young LLP 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.

We have a target to reduce 60 per cent or 19.7 million tonnes of our GHG emissions by 2030 over 2015 levels. In 2021, we set a new target to be carbon neutral by 2050. Our actions to reduce GHG emissions are aligned with the UN's SDGs, specifically "Goal 13: Climate Action." By 2030, we expect to have reduced close to 30 million tonnes over 2005 levels.

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 (forecast)	2020	2005
Total GHG emissions (million tonnes CO_2e)	**12.5**	16.4	41.9

In 2020, TransAlta increased its scoring on the CDP Climate Change investor request. Our overall score was an A-, indicating that we are implementing current best practices. This ranks the Corporation among industry leaders on climate change management and places us as ahead of most companies in North America. The average CDP score for our peers was a B and the average score for reporting companies in North America was a D.

Healthy, Safe, Diverse and Engaged Workplace: Human Capital Management

Engaging our workforce, developing our employees, creating a diverse and inclusive work environment and minimizing safety incidents are the keys to human capital value creation at TransAlta and our most material areas for management.

As of Dec. 31, 2020, we had 1,476 (2019 - 1,543) active employees. This number has decreased by four per cent from 2019 levels, following a reduction in positions in our coal fleet as part of our conversion to gas transition.

With approximately 41 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 109-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 Alberta Thermal, Centralia, North American 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 that 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 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 the 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 2020, we continued to progress our safety culture transformation despite an unprecedented and extraordinary challenge due to COVID-19. Behavioural safety training tools and capabilities have been reinforced through leadership peer board sessions and effective safety interactions. We also focused on the development of tools and training to support hazard identification, including updates to Field Level Hazard Assessment cards and a fleet-wide app for Occupation Hazard Assessment. Emphasis on safety interactions, interventions and positive observations for both employees and contractors was also a particular focus in 2020.

In 2020, we achieved a Total Injury Frequency ("TIF") rate of 1.67 compared to 1.12 in 2019. TIF tracks the total number of injuries, including minor first aids, relative to exposure hours worked. The increase in 2020 was a result of increased first aids across our fleet. This may have been due to an increase in contractor presence during projects/construction at our Sundance and Windrise facilities. The COVID-19 pandemic may also have had an impact with a potential for distraction while our workers adjusted to changes in their professional and personal lives.

In addition to TIF, we are 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 2020 was 0.81 compared to 0.73 in 2019. Minor adjustments were made to historical exposure hours, but our reported injuries, TIF and TRIF reporting did not change.

Safety at TransAlta (employees and contractors)	2020	2019	2018
Lost-time injuries	**5**	5	1
Medical aids	**9**	7	12
Restricted work injuries	**2**	3	12
First aids	**17**	8	23
Total TIF injuries	**33**	23	48
Exposure hours	**3,948,000**	4,108,000	5,014,000
Total Injury Frequency (TIF)	**1.67**	1.12	1.91
Total Recordable Injury Frequency (TRIF)	**0.81**	0.73	1.00

TRIF is our key safety metric for 2021. TRIF includes restricted work, medical aid and lost-time injuries. We are moving away from reporting TIF, which consists of the same injuries as TRIF, but also includes first aid incidents. We will continue to focus on overall injury reduction (including first aids) through our Significant Incident Communication process. This process ensures that incidents with high potential for loss are thoroughly investigated and lessons learned are shared across the fleet. Reporting TRIF also aligns with the SASB reporting framework.

In addition to TRIF, we have also introduced Total Safety Report Frequency as a key safety metric in 2021. This is a leading indicator that measures Total Safety Reports (hazard, near miss and positive observations) per worker per year. Total Safety Reports are proactive in nature and demonstrate the actions we are taking to identify and prevent an injury or loss from occurring. In this way, we not only manage incidents if they do occur, but methodically work to prevent them from arising in the first place.

As a demonstration to TransAlta's commitment to safety, SunHills Mining LP was awarded the Safety Excellence Award from the Alberta Mine Safety Association. This award is for best safety performance of all Alberta mines under one million workforce hours based on 2019 performance.

Equity, Diversity and Inclusion

TransAlta's commitment and focus on excellence in equity, diversity and inclusion ("ED&I") is found in our workplace amongst our co-workers who at all levels advocate for the core values of equity and inclusion. We believe a strong focus on ED&I will drive performance in innovation, improve service to our customers and positively impact the communities that we all live in.

In 2020, TransAlta formed a ED&I Council and empowered the Council to develop a long-term ED&I strategy. TransAlta also committed to a ED&I Pledge approved by our Board and executive team. The Pledge embodies our vision to strengthen our ED&I practices, and sets out four goals: (a) making our workplaces trusting places by having complex, and sometimes difficult, conversations about ED&I; (b) expanding education in ED&I; (c) creating best practices on meaningful ED&I initiatives; and (d) driving accountability on our ED&I initiatives by transparently reporting to our co-workers, executive team and Board.

In 2020, we also expanded our ED&I training, offering employees a platform for a variety of training, education and awareness on ED&I such as webinars, employee engagement sessions, articles, videos and blogs. Moreover, we obtained diversity and inclusion data from our inaugural ED&I Census, delivered by a third party, which was sent to all employees to understand our demographics and our experiences in the workplace. These census results will inform ED&I action plans for 2021 and beyond.

In early 2021, we received market recognition for our ED&I efforts and were certified by Diversio for our commitment to measuring, tracking and improving ED&I. The Diversio assessment and certification process has set the global standard for inclusion and being certified means that we have measured and set targets to increase diversity, we regularly collect data on our co-workers' experiences to identify bias and barriers faced by underrepresented groups, and we have implemented programs and policies designed to unlock specific challenges while tracking results.

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, 2020, women made up 43 per cent of our executive officer team and 45 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 21.5 per cent and the average percentage of women on executive teams is 16.8 per cent.

To further support female advancement, we have set targets to: (a) maintain equal pay for women in equivalent roles, (b) achieve 50 per cent representation of women on our Board by 2030 and (c) achieve 40 per cent representation of women among all employees by 2030. Our goal to achieve 40 per cent women across the entire workforce by 2030 is ambitious considering the majority of the operational roles are currently male dominated. Currently, women employees represent 21 per cent of all employees.

TransAlta was once again added to the Bloomberg Gender-Equality Index in 2021. 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. In 2020, TransAlta was also recognized on the *Globe and Mail*'s Women Lead Here inaugural survey and was included as an honoree for executive gender diversity in Canada.

Employee Retention & Recognition

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 and savings 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 executive members hired after Jan. 1, 2016. The Corporation's executive officers 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 certain locations. Our flexible benefit 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.

In 2020, we added Telehealth benefits that include employee access to virtual doctor visits, remote chronic condition management, and online or telephone access to medical support and information. We provide other health and dental benefits for disabled members and retired members, typically up to the age of 65. The Canadian retiree benefits plan was closed for all new hired employees as of March 1, 2017.

In 2020, the BOLT Awards were launched to provide timely rewards and recognition for work on transformational initiatives and project work, as well as to recognize above-and-beyond performance. The BOLT Awards have acted as an umbrella program whereby individual performance can be recognized in one place, frequently and in a consistent manner.

On an annual basis, TransAlta recognizes our top achievements through the President's Awards. During 2020, we added an additional award for Leadership Excellence. This award recognizes a people leader who consistently demonstrates TransAlta's values in their decision-making and actions, has a bias to action that achieves key business outcomes and is recognized by their team as a trusted advisor and mentor.

TransAlta's focus on organizational health resulted in top quartile results in 2020 benchmarked against 823 surveys and a total of 2.8 million respondents. This was accomplished by identifying eight priority practices and incorporating those practices into all facets of the organization.

Lastly, a Remote Work Program was developed in 2020 to provide employees with alternative permanent remote work options. This program allowed eligible employees to choose between working from home or within a TransAlta location.

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 2020, we continued with the Leadership Development Program that was launched the previous year. This program provided 143 leaders or future leaders with fundamental leadership skills and tools. Training programs focused on a variety of leadership competencies for participants with various years of management experience. In December 2019, we launched a Professional Development Library that contains over 600 articles on professional development and leadership and is updated on a monthly basis. We created this library with a Master Executive Coach and it is accessible to all employees. Since the creation of the library, we have had over 5,000 hits and we have over 375 regular users.

During 2020, TransAlta partnered with BetterUp, a consultancy providing professional coaching, to provide 1:1 coaching for 30 leaders. This was offered to people leaders as part of the Leadership Development initiative. BetterUp coaching is tailored to the individual's needs to allow them to work with their personal coach on areas that are important for them. Over the summer of 2020, 80 leaders were offered the Franklin Covey All Access Pass — this resource was packaged with our *7 Habits of Highly Effective People* training and expanded on the training with articles, videos and activities. The Senior Leadership also completed *The Good Fight* training, which focused on reframing perceptions on conflict and how to stop conflict avoidance. Remote work training was offered to all leaders and employees to help them work effectively in a remote setting.

During 2020, Alberta Merchant Market Training was developed internally by stakeholders in Operations, and Trading and Marketing. This training consisted of three modules, including power market fundamentals, the Alberta power market, generation portfolio and portfolio optimization, among other topics. This training was available to all employees to enhance their knowledge of the Alberta merchant market.

Partnering with Blue Ocean Brain, a micro-learning consultancy, TransAlta implemented compulsory ED&I training for all employees. This training included five modules on topics such as unconscious bias and allyship. In addition, Blue Ocean Brain was also engaged to provide 200 leaders with access to their learning library in 2021.

We launched the New Grad Program in 2020 with new graduates rotating through Corporate Finance, Trade Finance and HR. Each graduate participates in three rotations, each lasting eight months. This program is intended to develop knowledge and skills through work experience within multiple business units.

During 2020, TransAlta has had 17 intern and co-op placements with students in various areas of study including business, communications, finance and engineering. To assist in subsidizing the internship and co-op programs, TransAlta continues to partner with Electricity Human Resources Canada to access government funding. In 2020, TransAlta received wage subsidies of $120,000. In 2020, TransAlta also participated in the Canada Alberta Job Grant, which reimburses employers two-thirds of the cost of approved external training. TransAlta is currently approved to receive $56,000 to cover approved training costs.

Positive Indigenous, Stakeholder and Customer Relationships:
Social and Relationship Capital Management

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.

Human Rights

We operate in Canada, the US and Australia. All of these countries have high human rights standards. TransAlta respects the fundamental human rights of all its employees, contractors, suppliers, partners, Indigenous partners and other stakeholders. We abide by human rights legislation in all the jurisdictions in which we operate. We have a zero tolerance approach to discrimination based on age, disability, gender, race, religion, colour, national origin, political affiliation or veteran's status or any other prohibited ground as defined by human rights legislation in the jurisdictions in which we operate. We afford equal opportunities for men and women, support the right to freedom of association and the right to organize unions and bargain collectively. We do not conduct operational human rights reviews or impact assessments, but we do continue to operate aligned with the highest ethical standards, such as ISO 14001 and ISO 18001.

Indigenous Relationships and Partnerships

At TransAlta, we value our relationships and partnerships with stakeholders and our Indigenous partners. 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 fulfils 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 pow wows 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.

COVID-19 health measures posed challenges to how we engaged with Indigenous communities throughout 2020. However, we continued to have regular dialogue by telephone, email, video conference and whenever possible, in small group meetings while adhering to government health protocols. Our normal participation in Indigenous community events such as pow wows, blessing ceremonies, and school or recreational activities was not possible as social gatherings were not permitted during the pandemic. In response, our Indigenous Relations team determined it was important to reallocate funding for social events to support Indigenous communities and their expressed needs.

Support from TransAlta for Indigenous communities in response to the pandemic included the:

- Purchase and distribution of 400 school backpacks filled with grade-specific school supplies delivered to First Nation schools in Alberta to help alleviate pressures on household and community resources;
- Purchase of more than 200 Christmas gifts for school students at Mother Earth's Children's Charter School and Wihnemne School on Paul First Nation;
- Purchase of Christmas gift cards for Elders per requests from Piikani and Siksika Nations; and
- Funding for the purchase of COVID-19 testing equipment for the Alexis Nakota Sioux Nation.

Support for Indigenous Youth, Education and Employment

TransAlta recognizes the importance of investing in Indigenous students and our financial support helps students complete their education, become self-sufficient and give back to their communities. We are keen to help young Indigenous students reach their full potential and achieve their dreams. We also believe in providing financial support to Indigenous primary school students, helping to instill a passion for lifelong learning. In 2020, TransAlta provided more than $340,000 to support Indigenous youth, education and employment programs across Canada.

Highlights include:

- Entered into an agreement with Mount Royal University Foundation in support of the Indigenous Housing Renovation Fund, which will feature an Indigenous family tipi in an outdoor space dedicated to Indigenous students and supporting Indigenous cultural programming;
- Continued our partnership with Indspire, Canada's national Indigenous registered charity, and through this program, 10 bursaries of $3,000 each were given to recipients from the following communities: Ermineskin Cree Nation, Paul First Nation, Sunchild First Nation, Piikani Nation and Aamjiwnaang First Nation;
- Continued our support of Indigenous students with the Southern Alberta Institute of Technology ("SAIT") Gap program. This program provides critical financial support needed for aspiring Indigenous students who require high school upgrading in order to qualify for a trade program where there is a "gap" in available funding;
- In partnership with the United Way of Calgary & Area, designated funding to the Diamond Willow Youth Lodge, a safe place for Calgary Indigenous youth to connect with peers and participate in a variety of programs that promote health and wellness, education and employment preparation;
- Provided funding to the Lac Ste. Anne Métis Capacity Fund to support the training needs of community members including youth and women, and the provision of personal protective equipment for individuals entering the workforce; and
- Continued our ongoing partnership with the Banff Centre for Arts and Creativity with scholarship funding allocated to Indigenous community members to participate in Indigenous Leadership programming.

Cultural Awareness for TransAlta Employees

Our Indigenous Relations team led two cultural awareness initiatives for TransAlta employees in 2020. The first program was launched in June in recognition of National Indigenous History Month and National Indigenous Peoples Day (June 21). TransAlta hosted a virtual Lunch and Learn session featuring an interview with a community member from Paul First Nation and TransAlta's senior advisor for Indigenous & Stakeholder Relations, moderated by our Chief Legal, Regulatory, & External Affairs Officer. On Sept. 30, 2020, in recognition of Orange Shirt Day, TransAlta's Executive Leadership Team encouraged all employees to wear orange to promote awareness in Canada about the Indian residential school system and the impact it has had on Indigenous communities for over a century. In addition, a comprehensive educational program was designed and delivered to Operations leaders providing information on Indigenous history, culture, consultation requirements and TransAlta's relationship protocols and practices.

In 2021, we adopted a new sustainability target stating that all employees should complete Indigenous cultural awareness training by the end of 2023. We believe education is a key ingredient to ensure respectful and strong relationships into the future.

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 the Corporation. 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 knowledge 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	

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 business growth through proactive engagement with stakeholders in our geographic operating areas in Australia, Canada and the US to develop and maintain relationships, assess needs and fit, and 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, thereby minimizing project delays. We conduct consultation primarily during project development and decommissioning and maintain engaged communication throughout operations. For 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 record-keeping tool managed by our Stakeholder and Indigenous Relations team. This capacity fulfils 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 AFRC by writing to the AFRC or by making submissions via the Corporation's toll-free telephone or online Ethic Helpline (please refer to the "Governance and Risk Management - Risk Controls - 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 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 2020, representatives of the Board engaged extensively with the Corporation's significant shareholders. Specifically, since Jan. 1, 2020, the Board has met with 11 shareholders representing approximately 37 per cent of the Corporation's total issued and outstanding common shares.

Supply Chain – Sustainable Sourcing

We continue to seek solutions to advance supply chain sustainability. In 2020, we worked to optimize our global supply chain management operations by initiating the centralization and standardization of practices across our global operations. 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 2019, the Board 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 they pertain 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.

In addition, we rolled out a Supplier Relationship and Performance Management program in 2020 with a few of our key and strategic suppliers. The goals of the program include ensuring alignment of our suppliers' goals with those of TransAlta, streamlining communications while providing a platform to discuss how to elevate performance, creating value though access to innovative ideas and working closely with the suppliers on executing activities more cost-effectively.

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 security controls such as restricting physical access around and into our operating facilities. The use of security technology such as surveillance cameras and electronic access is utilized to ensure the control of secure areas. Regular audits and security risk assessments are conducted to ensure continuous improvement of the Security Management Program. Our Security Management Program is focused on protection of people, property, information and reputation.

The Corporate Emergency Management Program prepares employees should an emergency incident occur. The program includes an emergency management policy and standard, which sets an expectation for employees to continuously prepare for emergencies. The program has executive sponsorship. It provides the overarching framework for each business unit to provide an Emergency Response Plan and Business Continuity Plan. We implement our Incident Command System, which is a standardized on-scene emergency and incident management system that provides an organizational structure able to respond to single or multiple incidents. Designed to aid in the management of resources during incidents, it combines facilities, equipment, personnel, procedures and communications operating within a common organizational structure. It is used as part of an all-hazards approach for incident management and is officially recognized for multi-agency response in emergency situations, however complex.

We develop strong relationships with local emergency responders. We periodically conduct multi-agency training events at our facilities. This ensures continuous improvement, familiarity with our assets and builds strong communication channels for emergency response.

Our processes designate how we communicate with stakeholders in the event of a crisis. This is managed by our Crisis Communications Team. The team has the responsibility and goal to provide a unified message on behalf of Corporation throughout the response and recovery, ensure all messaging is approved by the Incident Commander (the Chief Talent & Transformation Officer, or their designate), co-ordinate messaging with any applicable external agencies and, if necessary, deploy to an incident site.

Annual training requirements are adhered to by our employees operating at our facilities. The results are tracked, audited and presented at our annual executive review. The findings and recommendations assist in maintaining a sustainable program across the organization.

Data and Digital Asset Protection

We work hard to protect our digital assets, including our corporate data and our digital identities that give us access into line of business applications. Cybersecurity risks that work to compromise these assets include the manipulation of data integrity, system and network hacking, use of social engineering tactics through email phishing, compromise of operations and infrastructure through the use of ransomware, credential breaches, attacks introduced through unknowing third-party vendors and service providers, as a well as malware. Given the ever-evolving nature of cyberattacks, we are consistently adapting our cybersecurity program to focus on three key pillars: technology, processes and people. Each of these pillars can be reinforced independently to address specific cyber risks and threats through a comprehensive and multi-faceted program. Through this program, TransAlta continually implements measures and controls to proactively mitigate internal and external cybersecurity risks and threats posed to the organization, and to deal efficiently and effectively with threats.

Please refer to Cybersecurity Risk in the Governance and Risk Management section of this MD&A for further details.

Community Investments

In 2020, TransAlta contributed approximately $2.2 million in donations and sponsorships (2019 - $2.1 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 $1.3 million for the United Way. TransAlta has been supporting the United Way for over 30 years and has contributed more than $20 million dollars over that time.

In 2020, we continued to focus our community investment on priority areas for TransAlta: youth and education, environmental leadership and community health and wellness. Some of our partnerships included:

- Indspire, Canada's national Indigenous registered charity, and through this program 10 bursaries of $3,000 each were given to recipients from the following communities: Ermineskin Cree Nation, Paul First Nation, Sunchild First Nation, Piikani Nation and Aamjiwnaang First Nation;
- Mother Earth's Children's Charter School ("MECCS") - Located in Treaty 6 territory, near Stony Plain, Alberta, and our Alberta coal operations, MECCS has become an important part of TransAlta's community investment program. MECCS offers education for students from 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. Due to the COVID-19 pandemic, this tradition needed to be conducted remotely. More than 200 Christmas gifts were purchased for students at Mother Earth's Children's Charter School and Wihnemne School on Paul First Nation;
- The Calgary Stampede – Founded in 2017, the TransAlta Performing Arts Studio at Stampede Park continues to provide a year-round facility for the Calgary Stampede Foundation and Calgary's youth performing arts groups to rehearse, train and celebrate the arts;
- SAIT Gap program, which provides critical financial support needed for aspiring Indigenous students who require high school upgrading in order to qualify for a trade program where there is a "gap" in available funding;
- TransAlta Tri-Leisure Centre - 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;
- The Banff Centre for Arts and Creativity – We continued our ongoing partnership with the Banff Centre with scholarship funding allocated to Indigenous community members to participate in Indigenous leadership training;
- Junior Achievement Southern Alberta – TransAlta continued to support the World of Choices program that gives students an opportunity to connect with mentors in a number of different careers. In 2020, this program was delivered online, allowing hundreds of students to connect with mentors and learn about different career opportunities;
- Calgary Reads – TransAlta was proud to continue our support for this organization that is dedicated to improving literacy skills for children in Calgary; 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 an 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. Three funding boards were formed to invest the $55 million: 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 $7 million, the Economic & Community Development Board $14 million and the Energy Technology Board $9 million. Specific projects that the boards funded in 2020 include energy-efficiency projects at local fire stations and low income housing, funding to support COVID-19 personal protection equipment for local businesses and schools, and a project to deploy the first renewable hydrogen fuelling station in the Pacific Northwest, which benefits both the electricity and transportation sectors.

Customers

TransAlta serves industrial and commercial customers with power and energy services across its fleet (Australia, Canada and the US). For more information on our customer focus, please refer to page 79 of this MD&A.

Technology Adoption and Innovation Focus: Manufactured Capital Management

Technology and innovation are an existing and increasing focus at TransAlta. As we navigate significant macro changes from energy transition, the impacts of climate change and decarbonization, and the continued rise of digital technology, automation and artificial intelligence, we are proactively applying technology solutions across our business. Our conversion of coal units to gas is an excellent example of utilizing useful manufactured capital or infrastructure. We also continue to adopt and apply innovative solutions to meet customer demand for power.

Innovation: Idea Generation and Project Management

Project Greenlight has been a key driver in ensuring the Corporation continues to provide year-over-year improvements in innovation. 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.

Another initiative we promote is the Supplier Innovation Series, which brings in guest speakers from outside TransAlta to discuss innovation. This includes thought leaders on new technologies to discuss conceptual ideas that initiate creative thinking and suppliers that provide insight into commercial applications of evolving technologies. In 2020, the topics discussed included artificial intelligence, virtual and augmented reality, robotic welding, the connected workforce, design thinking and innovation in safety. Subsequent to each session, small employee-led workshops consolidate ideas to further flesh out and drive new Greenlight initiatives.

Key priority practices addressed by the Supplier Innovation Series:

- Creativity and entrepreneurial thinking;
- Bottom-up innovation;
- Knowledge sharing; and
- Capturing external ideas.

For further details on our investment in our workforce, please see the Talent and Employee Development section of this MD&A.

Innovation: Infrastructure Innovation

In 2015, the Government of Alberta introduced regulations designed to end coal-powered generation in the province by 2030. A number of our coal facilities had useful lives beyond 2030 and could be converted to use natural gas. We are planning to convert or repower Alberta coal units to natural gas in the 2020 to 2023 time frame. Our Sundance 6 facility has recently been converted to gas. Through our conversion to gas and the repowering of Sundance 5, our energy use, GHG emissions, air emissions, waste generation and water usage will significantly decline. Repurposing the facilities rather than decommissioning them supports the concept of reuse and aligns with the UN's SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure."

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 and in 2020 we installed the first utility-scale battery in Alberta at our Summerview II wind facility. From 2000 to 2020, we have grown renewables capacity from approximately 900 MW to over 2,500 MW.

As we balance growth with decarbonization, we continue to seek solutions to innovate and create value for investors, society and the environment. This is evidenced by our continued execution of the accelerated conversion to gas plans, construction of the 207 MW Windrise wind project located in Alberta, and investment in the 137 MW Skookumchuck wind facility in Washington State. In 2020, we also acquired a contracted 29 MW cogeneration facility in Michigan. Cogeneration is recognized by regulatory bodies for its efficient generation of power when compared to other forms of natural gas power generation. It reduces the natural gas required by industrial processes by generating high-efficiency steam and power versus a boiler and grid supply approach. The distributed system also provides independence from the power grid and avoids the need to construct additional transmission lines.

We are also investing in battery storage. TransAlta began commercial operations of Alberta's first utility-scale lithium-ion battery storage facility, called WindCharger, on Oct. 15, 2020. This project is unique as it uses TransAlta's existing Summerview II wind facility to charge the battery, allowing WindCharger to be a truly renewable battery energy storage system. The project uses Tesla technology and has a nameplate capacity of 10 MW with a total storage capacity of 20 MWh. TransAlta received co-funding for this project from Emissions Reduction Alberta. The potential exists for the expansion of this technology, and we are investigating the viability of battery storage at our various wind facility locations and for use in developing customer-specific energy supply solutions.

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. We know that new technologies will emerge over the next number of years as the industry continues to drive towards lower emissions while maintaining a reliable and affordable product for customers. Our teams continue to be involved in assessing emerging technologies such as hydrogen and carbon capture and storage as well as the development of bespoke behind-the-fence solutions for customers using a combination of technologies such as renewables and batteries. 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 Australia, Canada and the US. A centralized team of engineers and operations specialists remotely monitors our power facilities for emerging equipment reliability and performance issues. ODC staff are trained in the development and use of specialized equipment monitoring software and they apply their experience to power facility operations. If an equipment issue is detected, the ODC notifies facility 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 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 facility operations.

Data & Innovation

TransAlta created the Data & Innovation team in 2019 to modernize its data infrastructure 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. In 2020, the Data & Innovation team worked with partners across the business to create new tools and processes that improve our financial position and return capacity to our people. A few of the highlights from this work include:

- GenOS, an innovative new platform where data is used to drive the actions of our assets and the decisions of our people, piloted with Wind Operations. This pilot project combines data and analytics from a variety of sources into one central web application and creates new opportunities to drive further adoption of automation across our operations; and
- Industry partnership with AltaML Applied AI Lab, a groundbreaking initiative that focuses on building and expanding local talent while improving our business through the application of machine learning and artificial intelligence.

2020 Sustainability Targets Performance

Sustainability Targets and Results

Our sustainability goals and targets support the long-term success of our business. Goals and targets are established to manage key or emerging material sustainability issues and to improve our performance in these areas.

We establish our goals and targets with reference to the UN's SDGs and the Future-Fit Business Benchmark. This focus ensures our goals and targets are meaningful in the broader context of solving societal problems; support the ambition of achieving a more sustainable, safe and just planet in the future; and ensure TransAlta's competitiveness, both today and in the future.

ESG Alignment: Environment			
TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Minimize fleet-wide environmental incidents	Keep annual significant environmental incidents below two and keep environmental regulatory non-compliance incidents below four	Not achieved	In 2020, we recorded six significant environmental incidents. None of these incidents was large in terms of magnitude or impact, which is consistent with past performance and suggests these types of incidents are not a major risk for the Corporation or the environment. For 2021, we are removing our target for environmental incidents but continuing to report on these events in the Incidents and Spills section of the MD&A. We are making this change to focus our targets on environmental areas that are more material for the Corporation.
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	On track	Reclamation work at our Centralia and Highvale mines was paused in 2020 due to the COVID-19 pandemic.
Reduce air emissions	By 2030, achieve a 95 per cent reduction of SO_2 emissions	On track	We are well on track to achieve our target of 95 per cent emission reductions of SO_2 by 2030. Since 2005, we have reduced SO_2 emissions by 83 per cent. In 2020, we reduced SO_2 emissions by approximately 4,000 tonnes over 2019 levels.
	By 2030, achieve a 50 per cent reduction of NO_x emissions below 2005 levels from TransAlta coal facilities	Achieved	We have achieved our target of 50 per cent emission reductions of NO_x by 2030 ahead of schedule. Since 2005, we have reduced NO_x emissions by 68 per cent. In 2020, we reduced approximately 5,000 tonnes of NO_x emissions over 2019 levels.
Reduce GHG emissions	By 2030, achieve company-wide GHG reductions of 60 per cent below 2015 levels, in line with a commitment to the UN SDGs and prevention of 2°C of global warming	On track	We are well on track to achieve our target of 60 per cent GHG emissions reductions by 2030. Since 2015, we have reduced GHG emissions by 80 per cent. In 2020, we reduced approximately 4.2 million tonnes of CO_2e over 2019 levels.

ESG Alignment: Social			
TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Reduce safety incidents	Achieve a Total Injury Frequency rate below 1.17	Not achieved	In 2020, we achieved a TIF of 1.67 compared to 1.12 in 2019. The increase in 2020 was a result of increased first aids across our fleet. This may have been due to an increase in contractor presence during projects and construction at our Sundance and Windrise facilities. There was also potentially an effect from adjustments that all of our workforce had to make due to the COVID-19 pandemic.

Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	Achieved	Support in 2020 represented a total value of $340,000 and provided bursaries 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.

ESG Alignment: Governance

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Strengthen gender equality	Achieve a quota of 50 per cent female representation on the Board by 2030	On track	As of Dec. 31, 2020, women made up 45 per cent of our Board.
	Achieve at least 40 per cent female employment among all employees of the Corporation by 2030	On track	As of Dec. 31, 2020, women made up 21 per cent of all employees, an increase over 2019 levels (20 per cent).
	Maintain equal pay for women in equivalent roles as men	Achieved	Equal pay for women in the Corporation was maintained in 2020.
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	Achieved	In 2020, we increased our alignment with the SASB sustainability reporting framework and increased our CDP Climate Change Scoring to an A-.

ESG Alignment: Environment and Social

TransAlta Sustainability Goal	TransAlta Sustainability Target	Results	Comments
Leading clean power company by 2025	By the end of 2025, convert coal facilities to gas through boiler conversions and combined-cycle repowering	On track	Our Sundance 6 coal facility began conversion to gas in 2020 and was completed in early 2021.
	No further coal generation by the end of 2025 and 100 per cent of our owned net generation capacity will be from clean electricity (renewables and gas)	On track	In 2020, we retired our Sundance 3 and Centralia 1 coal facilities, converted our Sundance 6 coal facility to gas and announced the acceleration of our Highvale mine closure to the end of 2021.
	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	Achieved	In 2020, the Corporation purchased a 49 per cent interest in the 137 MW Skookumchuck wind project and continued development of our 207 MW Windrise wind project. Our 10 MW WindCharger battery storage project also began commercial operations.

2021+ Sustainability Targets

Our 2021 and longer-term sustainability targets support the long-term success of our business. The following targets highlight our future ESG value proposition and paint a portrait of how the Corporation will continue to be positioned as an ESG leader in the future. Goals and targets are established to manage key and emerging material sustainability issues and to improve our performance in these areas. We continue to evolve and adapt our goals and targets to focus on anticipated key areas of sustainability materiality.

We establish our goals and targets with reference to the UN's SDGs and the Future-Fit Business Benchmark. This focus ensures our goals and targets are meaningful in the broader context of solving societal problems; support the ambition of achieving a more sustainable, safe and just planet in the future; and ensure TransAlta's competitiveness both today and in the future.

Targets are outlined below:

ESG Alignment: Environment		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN's SDG Target or Future-Fit Business Benchmark
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	Future-Fit Business Benchmark - "Positive Pursuits 13: Ecosystems are restored"
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	Future-Fit Business Benchmark - "Positive Pursuits 13: Ecosystems are restored"
Responsible water management	By 2026, reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent over the 2015 baseline	UN's SDG Target 6.4: "By 2030, substantially increase water-use efficiency across all sectors and ensure sustainable withdrawals and supply of freshwater to address water scarcity and substantially reduce the number of people suffering from water scarcity."
Reduce operational waste	By 2022, reduce total waste generation by 80 per cent over a 2019 baseline	UN's SDG Target 12.5: "By 2030, substantially reduce waste generation through prevention, reduction, recycling and reuse."
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NO_x emissions below 2005 levels	UN's 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 per cent below 2015 levels, in line with a commitment to the UN's SDGs and prevention of 2°C of global warming	UN's SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning."
	By 2050, achieve carbon neutrality	

ESG Alignment: Social		
TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN's SDG Target or Future-Fit Target
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.61	UN's 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's 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."
	Provide Indigenous cultural awareness training to all TransAlta employees by the end of 2023	UN's SDG Target 12.8: "By 2030, ensure that people everywhere have the relevant information and awareness for sustainable development and lifestyles in harmony with nature."

ESG Alignment: Governance

TransAlta Sustainability Goal	TransAlta Sustainability Target	Alignment with UN's 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's 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's 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's SDG Target or Future-Fit Target
Coal transition	No further coal generation by the end of 2025 and 100 per cent of our owned net generation capacity will be from clean electricity (renewables and gas)	UN's SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services."
	Discontinue coal power generation in Canada by the end of 2021	UN's SDG Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services."
Clean energy solutions for customers	Develop new renewable projects that support customer sustainability goals to achieve both long-term power price affordability and carbon reductions	UN's 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 a 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 CEO, are independent within the meaning of National Instrument 58-101 - D*isclosure of Corporate Governance Practices*;
- 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 of the Board'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, 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: a) receiving regular reports from management regarding environmental compliance, trends and TransAlta's responses; b) 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; c) assessing the impact of the GHG policies implementation and other legislative initiatives on the Corporation's business; d) reviewing with management the EH&S policies of the Corporation; e) 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; f) discussing with management ways to improve the EH&S processes and practices; and g) 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 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: a) reviewing and considering the substantive risks, returns, financing and other key elements relating to the Corporation's major capital projects; b) reviewing and assessing mitigation plans, expected outcomes, and implementation throughout the project life cycle with respect to substantive risks; c) reviewing and assessing cost-estimating methodologies employed throughout the project life cycle; d) reviewing and assessing progress reports including periodic updates on the project schedule, risks and costs at key milestones as projects advance through to execution; e) reviewing post-project look-backs; and f) 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 executive 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 Executive Vice-President, Finance & Trading and Chief Financial Officer.

The Investment Committee is chaired by our CEO and is comprised of the CEO, Executive Vice-President, Finance & Trading and Chief Financial Officer, Chief Operating Officer, Chief Development Officer, and Executive Vice-President, Legal, Commercial and External Affairs. It reviews and approves all major capital expenditures including growth, productivity, life extensions and major coal outages. Projects that are approved by the Investment Committee will then be put forward for approval by the Board, if required.

The Commodity Risk & Compliance Committee is chaired by our Executive Vice-President, Finance & Trading and Chief Financial Officer and is comprised of at least three members of senior management. 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 members who are Brookfield employees with expertise in hydro facility management, and two TransAlta members. This committee was formed in 2019 for the purpose of collaborating on matters in connection with the operation, and maximization of 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: a) Multilateral Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*; b) National Instrument 52-110 - *Audit Committees*; c) National Policy 58-201 - *Corporate Governance Guidelines*; and d) 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.

COVID-19

We have adopted a number of risk mitigation measures in response to the COVID-19 pandemic, including the formal implementation of TransAlta's business continuity plan on March 9, 2020. The Board and management have been monitoring the development of the outbreak and are continually assessing its impact on the Corporation's operations, supply chains and customers, as well as, more generally, to the business and affairs of the Corporation. Potential impacts of the pandemic on the business and affairs of the Corporation include, but are not limited to: potential interruptions of production, supply chain disruptions, unavailability of employees at TransAlta, potential delays in growth projects, increased credit risk with counterparties and increased volatility in commodity prices and the valuations of financial instruments. In addition, the broader impacts to the global economy and financial markets could have potential adverse impacts on the availability of capital for investment and the demand for power and commodity pricing.

To manage the risks resulting from COVID-19, we have taken a number of steps in furtherance of the Corporation's business continuity efforts:

Management Responses

- Formed a COVID-19 emergency team run by our Chief Operating Officer, reporting to the CEO;
- Regularly communicated with the Board and employees in regard to the Corporation's response to COVID-19;
- Created a team to develop, implement and update COVID-19 safety protocols, including a back-to-office and site strategy that will remain in place until a vaccine has been distributed;
- Established a committee to consider and respond to any claims of force majeure that may be received as a result of COVID-19; and
- Developed leadership plans, including contingent authorities.

Policy Changes

- Aligned all non-essential travel and quarantine requirements with local jurisdictional guidance for all TransAlta employees and contractors returning from air, bus, train or ship travel for all jurisdictions in which we operate.

Employee Changes

- Provided assurances to employees that their employment with TransAlta would not be impacted by the COVID-19 pandemic;
- Developed and implemented COVID-19-specific back-to-office protocols to ensure all TransAlta locations remain safe;
- Requested and received an essential workers quarantine exemption approval from Alberta Health to minimize disruptions in the event international technical assistance is required for our Alberta assets;
- Implemented health screening procedures, including questionnaires and temperature tests, enhanced cleaning measures and strict work protocols at the Corporation's offices and facilities in accordance with our back-to-office and site strategy;
- Implemented training and policies to seamlessly allow non-essential employees to work remotely, as appropriate; and
- Provided COVID-19 related town halls and information sessions for employees featuring medical and infectious disease experts.

Operational Changes

- Modified our operating procedures and implemented restrictions to non-essential access to our facilities to support continued operations through the pandemic;
- Reviewed the supply chain risk associated with all key power-generation process inputs and implemented weekly monitoring for changes in risk;
- Reached out to key supply chain contacts to determine strategies and contingencies to ensure we are able to continue to progress our growth projects, wherever possible; and
- Identified new cybersecurity risks associated with phishing emails and enhanced security protocols and increased awareness of potential threats.

Financial Oversight

- Continued to maintain a comprehensive commodity hedging program for our merchant assets that can respond to changes in underlying market conditions;
- Continued to monitor counterparties for changes in creditworthiness, as well as monitor their ability to meet obligations; and
- Continued to monitor the situation and communicate with our key lenders on any foreseeable impacts and on our response to the crisis. We maintain a strong financial position and significant liquidity with our existing committed credit facilities.

Overall, we continue to actively monitor the situation and advice from public health officials with a view to responding to changing recommendations and adapting our response and approach as necessary.

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 any laws or our code 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, 2020, associated with our proprietary commodity risk management activities was $1 million (2019 - $1 million). Please 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 2020. 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 facilities 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 facility maintenance so that our facilities 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 facilities are exposed to operational risks such as failures due to cyclic, thermal and corrosion damage in boilers, generators and turbines, as well as other issues that can lead to outages and increased volume risk. If facilities 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 optimize the life cycles of our existing facilities and/or identify 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 facilities 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 2020, we had approximately 90 per cent (2019 — 90 per cent) of production under short-term and long-term contracts and hedges. In the event of a planned or unplanned 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 facilities;
- Hedging emissions costs by entering into various emission trading arrangements; and
- Selectively using hedges, where available, to set prices for fuel.

In 2020, 89 per cent (2019 — 66 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 78 per cent (2019 — 76 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 facilities, 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 facilities are some of the exposures in our operations. Additionally, the ability of the mines to deliver coal to the power facilities can be impacted by weather conditions and labour relations. At Centralia, 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;
- Sourcing the coal used at Centralia from different mine sources to ensure sufficient coal is available at a competitive cost;
- Contracting sufficient trains to deliver the coal requirements at Centralia;
- Ensuring coal inventories on hand at Alberta Thermal and Centralia 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 facilities;
- Co-firing natural gas with coal;
- Monitoring the financial viability of Centralia 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 facilities, and ultimately converting these facilities 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:

- Working to ensure 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 pipeline 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 and imposing additional costs on the generation of electricity through such measures as emission caps or taxes, 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 are committed to remaining 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 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.

Amidst the current economic conditions resulting from the COVID-19 pandemic, TransAlta has implemented the following additional measures to monitor its counterparties for changes in their ability to meet obligations:

- daily monitoring of events impacting counterparty creditworthiness and counterparty credit downgrades;
- weekly oversight and follow-up, if applicable, of accounts receivables; and
- review and monitoring of key suppliers, counterparties and customers (i.e., offtakers).

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

Our credit risk management profile and practices have not changed materially from Dec. 31, 2019. We had no material counterparty losses in 2020. 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, 2020:

	Investment grade *(%)*	Non-investment grade *(%)*	Total *(%)*	Total amount
Trade and other receivables[1]	92	8	**100**	**583**
Long-term finance lease receivables	100	—	**100**	**228**
Risk management assets[1]	93	7	**100**	**692**
Loan receivable[2]	—	100	**100**	**52**
Total				**1,555**

(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 $22 million (2019 — $5 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 a combination of interest expense on our Australian-dollar denominated debt and 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	$12 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, 2020, we have liquidity of $2.1 billion comprised of amounts not drawn under our committed credit facilities and cash on hand that is available to draw on for projects in 2021.

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. 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, 2020, approximately seven per cent (2019 — 11 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	30	$1 million before tax

IBOR reform could impact interest rate risk with respect to the Corporation's credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The facility references LIBOR for US-dollar drawings and the Canadian Dollar Offer Rate ("CDOR") for Canadian-dollar drawings; in addition, the non-recourse bond references the three-month CDOR. To date, no US-dollar drawings have been made on the facility and there is currently a plan to discontinue the six- and 12-month CDOR, which does not impact the facility or the non-recourse bond.

Outstanding forward starting interest rate swaps in both Canadian and US dollars should not be affected as they are set to settle in 2021 prior to any IBOR changes being made. The Corporation is monitoring the reform and does not expect any material impacts.

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 2020, 46 per cent (2019 — 46 per cent) of our labour force was covered by 10 (2019 — 10) collective bargaining agreements. In 2020, two (2019 — four) agreements were renegotiated. We anticipate the successful negotiation of three collective agreements in 2021.

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 within each of the jurisdictions in which we operate. 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 carbon pricing policies and funding.

We manage these risks systematically through our Legal and Regulatory groups and our Compliance program, which is reviewed periodically to ensure its effectiveness. We also 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 consultations 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 facilities 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 faster 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 people. 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 cyber insurance (as well as 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	$3 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 and merits 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. Please 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, 2020. 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"). For the year ended Dec. 31, 2020, the majority of our workforce supporting and executing our ICFR and DC&P worked remotely. There has been minimal impact to the design and performance of our internal controls. Management has reviewed the changes as a result of changes implemented in response to COVID-19 and is reasonably assured that adjustments to process have not 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 MD&A. Based on the foregoing evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as at Dec. 31, 2020, the end of the period covered by this MD&A, 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 fulfills 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

Todd Stack
Executive Vice President, Finance and Chief Financial Officer

March 2, 2021

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 joint operations of the Sheerness Generating Station, and Pioneer Pipeline Limited Partnership and we equity account for our investments in SP Skookumchuck Investment, LLC and EMG International, LLC in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements and associates. Once the financial information is obtained from these joint arrangements and associates 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 and associates.

Included in the 2020 Consolidated Financial Statements of TransAlta for joint operations and equity accounted investments are $481 million and $394 million of total and net assets, respectively, as of December 31, 2020, and $112 million and $6 million of revenues and net earnings (loss), respectively, for the year then ended.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2020, 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, 2020, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and
Chief Financial Officer

March 2, 2021

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, 2020, 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, 2020, based on the COSO criteria.

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 joint operations and equity accounted investments of the Sheerness Generating Station, Pioneer Pipeline Limited Partnership, SP Skookumchuk Investment, LLC and EMG International, LLC, which are included in the 2020 consolidated financial statements of TransAlta Corporation and constituted $481 million and $394 million of total and net assets, respectively, as of December 31, 2020, and $112 million and $6 million of revenues and net earnings (loss), respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation also did not include an evaluation of the internal control over financial reporting of the joint operations and equity accounted investments of the Sheerness Generating Station, Pioneer Pipeline Limited Partnership, SP Skookumchuck Investment, LLC and EMG International, LLC.

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, 2020 and 2019, 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, 2020, and the related notes and our report dated March 2, 2021 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 generally accepted accounting principles. 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 generally accepted accounting principles, and that receipts and expenditures of the corporation are being made only in accordance with authorizations of management and directors of the corporation; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the corporation's assets that could have a material effect on the financial statements.

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

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
March 2, 2021

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, 2020 and 2019, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

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, 2020, 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 2, 2021 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 Centralia Thermal Plant cash generating unit ("CGU") & Goodwill related to the Wind and Solar segment

Description of the Matter

As disclosed in notes 2(I), 2(J), 2(Z)(II), 18 and 21 of the consolidated financial statements, the Corporation owns significant power generation assets which are required to be reviewed for indicators of impairment at the CGU level and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually. Long lived assets for the Centralia Thermal Plant CGU are included in the Centralia segment which amounts to $260 million. Goodwill related to the Wind and Solar segment amounts to $175 million.

We identified the assessment of indicators of impairment for the Centralia Thermal Plant CGU 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 the Wind and Solar segment for the purposes of the annual goodwill impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgement applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include forecasted 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 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 the Wind and Solar segment 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 amounts. 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 the inputs against available market data.

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(Z)(V) and 15 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, 2020 the Corporation's derivative financial instruments classified as level III were $582 million.

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, discount rates, volatility, unit availability and demand profiles, and can fluctuate significantly depending on market conditions. Therefore, such determination of fair value was identified as a critical audit matter.

How We Addressed the Matter in Our Audit

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 compared management's future pricing assumptions, credit valuation adjustments, and liquidity assumptions to third-party data as well as comparing terms such as volumes and timing to executed commodity contracts. We compared the unit availability and demand profile assumptions to historical information. 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 level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates by evaluating the key assumptions and methodologies.

Ernst & Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.
Calgary, Canada
March 2, 2021

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2020**	2019	2018
Revenues (Note 5)	**2,101**	2,347	2,249
Fuel, carbon compliance and purchased power (Note 6)	**968**	1,086	1,100
Gross margin	**1,133**	1,261	1,149
Operations, maintenance and administration (Note 6)	**472**	475	515
Depreciation and amortization	**654**	590	574
Asset impairment charge (Note 7)	**84**	25	73
Gain on termination of Keephills 3 coal rights contract (Note 4(R))	**—**	(88)	—
Taxes, other than income taxes	**33**	29	31
Termination of Sundance B and C PPAs (Note 4(S))	**—**	(56)	(157)
Net other operating income (Note 9)	**(11)**	(49)	(47)
Operating income	**(99)**	335	160
Equity income (Note 10)	**1**	—	—
Finance lease income	**7**	6	8
Net interest expense (Note 11)	**(238)**	(179)	(250)
Foreign exchange gain (loss)	**17**	(15)	(15)
Gain on sale of assets and other (Note 4(R) and 18)	**9**	46	1
Earnings (loss) before income taxes	**(303)**	193	(96)
Income tax expense (recovery) (Note 12)	**(50)**	17	(6)
Net earnings (loss)	**(253)**	176	(90)
Net earnings (loss) attributable to:			
TransAlta shareholders	**(287)**	82	(198)
Non-controlling interests (Note 13)	**34**	94	108
	(253)	176	(90)
Net earnings (loss) attributable to TransAlta shareholders	**(287)**	82	(198)
Preferred share dividends (Note 28)	**49**	30	50
Net earnings (loss) attributable to common shareholders	**(336)**	52	(248)
Weighted average number of common shares outstanding in the year *(millions)*	**275**	283	287
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 27)	**(1.22)**	0.18	(0.86)

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2020**	2019	2018
Net earnings (loss)	**(253)**	176	(90)
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**(11)**	(26)	15
Losses on derivatives designated as cash flow hedges, net of tax	**(1)**	—	—
Total items that will not be reclassified subsequently to net earnings	**(12)**	(26)	15
Gains (losses) on translating net assets of foreign operations, net of tax	**(11)**	(59)	84
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax	**11**	21	(41)
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**20**	61	(8)
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(3)	**(110)**	(42)	(46)
Total items that will be reclassified subsequently to net earnings	**(90)**	(19)	(11)
Other comprehensive income (loss)	**(102)**	(45)	4
Total comprehensive income (loss)	**(355)**	131	(86)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(439)**	54	(210)
Non-controlling interests (Note 13)	**84**	77	124
	(355)	131	(86)

(1) Net of income tax recovery of $3 million for the year ended Dec. 31, 2020 (2019 — $7 million recovery, 2018 — $5 million expense).
(2) Net of income tax expense of $8 million for the year ended Dec. 31, 2020 (2019 —$16 million expense, 2018 — $1 million recovery).
(3) Net of reclassification of income tax expense of $31 million for the year ended Dec. 31, 2020 (2019 —$10 million expense, 2018 — $11 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2020**	2019
Cash and cash equivalents	**703**	411
Restricted cash (Note 24)	**71**	32
Trade and other receivables (Note 14)	**583**	462
Prepaid expenses	**31**	19
Risk management assets (Note 15 and 16)	**171**	166
Inventory (Note 17)	**238**	251
Assets held for sale (Note 4(B) and 7)	**105**	—
	1,902	1,341
Investments (Note 10)	**100**	—
Long-term portion of finance lease receivables (Note 8)	**228**	176
Risk management assets (Note 15 and 16)	**521**	640
Property, plant and equipment (Note 18)		
Cost	**13,398**	13,395
Accumulated depreciation	**(7,576)**	(7,188)
	5,822	6,207
Right-of-use assets (Note 19)	**141**	146
Intangible assets (Note 20)	**313**	318
Goodwill (Note 21)	**463**	464
Deferred income tax assets (Note 12)	**51**	18
Other assets (Note 22)	**206**	198
Total assets	**9,747**	9,508
Accounts payable and accrued liabilities	**599**	413
Current portion of decommissioning and other provisions (Note 23)	**59**	58
Risk management liabilities (Note 15 and 16)	**94**	81
Current portion of contract liabilities (Note 5)	**1**	1
Income taxes payable	**18**	14
Dividends payable (Note 27 and 28)	**59**	37
Current portion of long-term debt and lease liabilities (Note 24)	**105**	513
	935	1,117
Credit facilities, long-term debt and lease liabilities (Note 24)	**3,256**	2,699
Exchangeable securities (Note 25)	**730**	326
Decommissioning and other provisions (Note 23)	**614**	488
Deferred income tax liabilities (Note 12)	**396**	472
Risk management liabilities (Note 15 and 16)	**68**	29
Contract liabilities (Note 5)	**14**	14
Defined benefit obligation and other long-term liabilities (Note 26)	**298**	301
Equity		
Common shares (Note 27)	**2,896**	2,978
Preferred shares (Note 28)	**942**	942
Contributed surplus	**38**	42
Deficit	**(1,826)**	(1,455)
Accumulated other comprehensive income (Note 29)	**302**	454
Equity attributable to shareholders	**2,352**	2,961
Non-controlling interests (Note 13)	**1,084**	1,101
Total equity	**3,436**	4,062
Total liabilities and equity	**9,747**	9,508

Significant and subsequent events (Note 4)
Commitments and contingencies (Note 36)

On behalf of the Board:

John P. Dielwart
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, 2018	$3,059	$942	$11	$ (1,496)	$481	$2,997	$1,137	$4,134
Adjustments on implementation of IFRS 16	—	—	—	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 of 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 (Note 4(V) and 13)	—	—	—	5	1	6	22	28
Effect of share-based payment plans	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
Net earnings (loss)	—	—	—	(287)	—	(287)	34	(253)
Other comprehensive income (loss):								
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(91)	(91)	—	(91)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(11)	(11)	—	(11)
Intercompany FVOCI investments	—	—	—	—	(50)	(50)	50	—
Total comprehensive income (loss)				(287)	(152)	(439)	84	(355)
Common share dividends	—	—	—	(58)	—	(58)	—	(58)
Preferred share dividends	—	—	—	(49)	—	(49)	—	(49)
Shares purchased under NCIB	(79)	—	—	18	—	(61)	—	(61)
Changes in non-controlling interests in TransAlta Renewables	—	—	—	5	—	5	15	20
Effect of share-based payment plans (Note 30)	(3)	—	(4)	—	—	(7)	—	(7)
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(116)	(116)
Balance, Dec. 31, 2020	**2,896**	**942**	**38**	**(1,826)**	**302**	**2,352**	**1,084**	**3,436**

(1) Refer to Note 29 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)*	**2020**	2019	2018
Operating activities			
Net earnings (loss)	**(253)**	176	(90)
Depreciation and amortization (Note 37)	**798**	709	710
Net gain on sale of assets (Note 4(I) Note 4(R))	**(9)**	(45)	—
Accretion of provisions (Note 23)	**30**	23	24
Decommissioning and restoration costs settled (Note 23)	**(18)**	(34)	(31)
Deferred income tax recovery (Note 12)	**(85)**	(18)	(34)
Unrealized (gain) loss from risk management activities	**42**	(32)	30
Unrealized foreign exchange loss	**1**	13	28
Provisions	**9**	13	7
Asset impairment (Note 7)	**84**	25	73
Equity income, net of distributions from Joint Ventures	**(1)**	—	—
Other non-cash items	**15**	(102)	147
Cash flow from operations before changes in working capital	**613**	728	864
Change in non-cash operating working capital balances (Note 33)	**89**	121	(44)
Cash flow from operating activities	**702**	849	820
Investing activities			
Additions to property, plant and equipment (Note 18 and 37)	**(486)**	(417)	(277)
Additions to intangible assets (Note 20 and 37)	**(14)**	(14)	(20)
Restricted cash (Note 24)	**(39)**	34	(35)
Loan receivable (Note 22)	**(5)**	(10)	1
Acquisitions, net of cash acquired (Note 4)	**(32)**	(117)	(30)
Acquisition of investments (Note 10)	**(102)**	—	—
Investment in the Pioneer Pipeline	**—**	(83)	(15)
Proceeds on sale of property, plant and equipment	**6**	13	2
Realized gains on financial instruments	**2**	3	2
Decrease in finance lease receivable	**17**	24	59
Other	**(12)**	23	15
Change in non-cash investing working capital balances	**(22)**	32	(96)
Cash flow used in investing activities	**(687)**	(512)	(394)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 24)	**(106)**	(119)	312
Repayment of long-term debt (Note 24)	**(489)**	(96)	(1,179)
Issuance of long-term debt (Note 24)	**753**	166	345
Issuance of exchangeable securities (Note 25)	**400**	350	—
Dividends paid on common shares (Note 27)	**(47)**	(45)	(46)
Dividends paid on preferred shares (Note 28)	**(39)**	(40)	(40)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4(W))	**—**	—	144
Repurchase of common shares under NCIB (Note 27)	**(57)**	(68)	(23)
Realized gains on financial instruments	**3**	—	48
Distributions paid to subsidiaries' non-controlling interests (Note 13)	**(97)**	(106)	(165)
Decrease in lease liabilities (Note 24)	**(25)**	(21)	(18)
Financing fees and other	**(11)**	(35)	(31)
Change in non-cash financing working capital balances	**(13)**	—	2
Cash flow from (used in) financing activities	**272**	(14)	(651)
Cash flow from (used in) operating, investing, and financing activities	**287**	323	(225)
Effect of translation on foreign currency cash	**5**	(1)	—
Increase (decrease) in cash and cash equivalents	**292**	322	(225)
Cash and cash equivalents, beginning of year	**411**	89	314
Cash and cash equivalents, end of year	**703**	411	89
Cash income taxes paid	**36**	35	87
Cash interest paid	**201**	185	188

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: Hydro, Wind and Solar, North American Gas, Australian Gas, Alberta Thermal, and Centralia. 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. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment LLC. 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 Alberta Thermal 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 and Other Segment

The Corporate and Other segment includes the Corporation's central finance, legal, administrative, corporate development and investor relation functions. Activities and charges directly or reasonably attributable to other segments are allocated thereto. In 2020, the Corporate and Other segment also includes the investment in EMG International, LLC ("EMG"), a wastewater treatment processing company.

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on March 2, 2021.

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

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 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.

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 stand-alone 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.

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

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 "pass-through" 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.

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:

Hydro generation	1-52 years
Wind generation	1-29 years
Gas generation	1-17 years
Coal generation	1-29 years
Mining property and equipment	1-9 years
Capital spares and other	2-52 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 "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. Unrecognized deferred tax assets are re-assessed at each reporting date and are recognised to the extent that it has become probable that future taxable income will allow the deferred income tax asset to be recovered.

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)) to the extent the related PP&E asset is still in use. Where the related PP&E asset has reached the end of its useful life, changes in the decommissioning and restoration provision 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. 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. Lease Policy for 2019 and 2020

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 liabilities in the Consolidated Statements of Earnings (Loss); and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

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. Investments in Associates
Associates are entities over which the Corporation has significant influence. Significant influence is the power to participate in financial and operating policy decisions of the entity, but is not control or joint control over the policies. Significant influence is generally present when an investor holds more than 20 per cent of the voting power of the investee.

Investments in associates are accounted for using the equity method of accounting. 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 associate’s net earnings or loss after the date of acquisition. The Corporation’s share of the associate’s net earnings or loss is recognized in net earnings. Distributions received from the associate reduce the carrying amount of the investment

Investments in associates 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. Any impairment loss is recognized within equity income in the statement of earnings.

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

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

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

X. Business Combinations

Transactions in which the acquisition constitutes a business are accounted for using the acquisition method. Identifiable assets acquired and liabilities assumed are measured at their acquisition date fair values. 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.

Y. Stripping Costs

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

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. COVID-19

The outbreak of the novel strain of coronavirus ("COVID-19") has resulted in governments worldwide enacting emergency measures to constrain the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods, self-isolation, physical and social distancing and the closure of non-essential businesses, have caused significant disruption to businesses globally, which has resulted in an uncertain and challenging economic environment. The duration and impact of the COVID-19 pandemic are unknown at this time. Estimates to the extent to which the COVID-19 pandemic may, directly or indirectly, impact the Corporation's operations, financial results and conditions in future periods are also subject to significant uncertainty. For a description of additional risks identified as a result of the pandemic, refer to Note 16. Actual results could differ from these 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.

II. 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 2018 to 2020 is found in Notes 7, 18 and 21.

III. 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.

IV. 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 12 for further details on the impacts of the Corporation's tax policies.

V. 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 15. 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.

VI. Project Development Costs

Project development costs are capitalized in accordance with the accounting policy in Note 2(K). Management is required to use judgment to determine if there is reason to believe that future costs are recoverable, and that efforts will result in future value to the Corporation, in determining the amount to be capitalized. Information on the write-off of project development costs is disclosed in Note 7.

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 23. 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 2020 in respect of decommissioning and restoration provisions can be found in Note 3(A)(III) and Notes 7 and 23.

VIII. Useful Life of PP&E

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

IX. Employee Future Benefits

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 31 for disclosures on employee future benefits.

X. 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, 9 and 23 with respect to other provisions.

XI. 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 the 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 stand-alone 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.

XII. 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.

XIII. Significant Influence
Upon entering into an investment, the Corporation must classify it as either an investment as an associate or an investment under IFRS 9. In making this classification, the Corporation exercises judgment in evaluating whether the Corporation has significant influence over the investee. Significant influence is the power to participate in the financial and operating policy decisions of the investee, but is not control or joint control over those policies. If the Corporation holds 20 per cent or more of the voting rights in the investee, it is presumed that the entity has significant influence, unless it can be clearly demonstrated that this is not the case. Other factors such as representation on the board of directors, participation in policy-making processes, material transactions between the Corporation and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Corporation has significant influence over an investee.

3. Accounting Changes
A. Current Accounting Changes
I. Amendments to IAS 1 and IAS 8 *Definition of Material*
The Corporation adopted the amendments to IAS 1 and IAS 8 as of Jan. 1, 2020. The amendments provide a new definition of material that states "information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity."

The amendments clarify that materiality will depend on the nature or magnitude of information, either individually or in combination with other information, in the context of the financial statements. A misstatement of information is material if it could reasonably be expected to influence decisions made by the primary users. These amendments had no impact on the consolidated financial statements of, nor is there expected to be any future impact to, the Corporation.

II. Amendments to IFRS 7 and 9 *Interest Rate Benchmark Reform*

In September 2019, the IASB issued amendments to the IFRS relating to *Interest Rate Benchmark Reform* - amending IFRS 9, IAS 39 and IFRS 7. These amendments provide temporary relief during the period of uncertainty from applying specific hedge accounting requirements to hedging relationships directly affected by the ongoing interest rate benchmark reforms. These amendments are mandatory for annual periods beginning on or after Jan. 1, 2020. The Corporation adopted these amendments as of Jan. 1, 2020. There were no hedging relationships that were directly affected on Jan. 1, 2020.

During the first quarter of 2020, the Corporation entered into cash flow hedges of interest rate risk associated with a future forecasted debt issuance using London Interbank Offered Rate ("LIBOR") based derivative instruments. As a temporary relief, provided by the IFRS 9 amendments, the Corporation has assumed that the LIBOR interest rate on which the cash flows of the interest rate swaps are based is not altered by interbank offered rates ("IBOR") reform when assessing if the hedge is highly effective.

III. Change in Estimates

Useful Life of PP&E at Alberta Thermal

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. This resulted in an increase of $15 million in depreciation expense that was recognized in the Consolidated Statements of Earnings (Loss) during the second half of 2020. As at Dec. 31, 2020, the carrying value of the Highvale mine, including PP&E, right-of-use assets and intangible assets, was $373 million,

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(B), the Corporation adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense and intangibles amortization for the year ended Dec.31, 2018, increased by $38 million.

In the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment charge of $38 million for the remaining net book value of the asset. In the third quarter of 2020, the Corporation recognized an impairment on Sundance Unit 3 in the amount of $70 million, due to the Corporation's decision to retire the unit. The retirement decision for Sundance Unit 3 was largely driven by an assessment of future market conditions, the age and condition of the unit, and our ability to supply energy and capacity from our generation portfolio in Alberta.

Useful Life of PP&E at 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 facility 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.

Decommissioning and other provisions

In the fourth quarter of 2020, the Corporation adjusted the Sarnia decommissioning and restoration provision to reflect an updated engineering study. The Corporation's current best estimate of the decommissioning and restoration provision decreased by $15 million. This resulted in a decrease in the related assets in PP&E.

In the third quarter of 2020, the Corporation adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity including increased volume of material movement. The Corporation's current best estimate of the decommissioning and restoration provision increased by $75 million. This resulted in an increase in the related assets in PP&E.

During the third quarter of 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believed that the fine coal recovery and reclamation work would be completed as originally proposed. At the end of 2019, the Corporation's 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 resulted in the immediate recognition of the full $141 million, through asset impairment in net earnings.

B. Future Accounting Changes

Amendments to IAS 16 *Property, Plant and Equipment: Proceeds before Intended Use*

The Corporation plans to early adopt the amendments to IAS 16 *Property, Plant and Equipment: Proceeds before Intended Use* on Jan. 1, 2021. The amendment has a mandatory effective date of Jan. 1, 2022. The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing the asset to the location and condition necessary for it to be capable of operating. No adjustments are expected from early adopting the amendments.

IFRS 7 *Financial Instruments, Disclosures* - Interest Rate Benchmark Reform

The IASB issued *Interest Rate Benchmark Reform — Phase 2* in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial Instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments are effective Jan. 1, 2021, and will be adopted by the Corporation in 2021, no financial impact is expected upon adoption.

C. Comparative Figures

Certain comparative figures have been reclassified to conform to the current period’s presentation. These reclassifications did not impact previously reported net earnings.

4. Significant and Subsequent Events

A. Clean Energy Investment Plan

TransAlta's Clean Energy Investment Plan announced in 2019 includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in on-site 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 Clean Energy Investment Plan includes converting three of our existing Alberta thermal units to gas during 2021 by replacing existing coal burners with natural gas burners. The cost to convert each unit is expected to be approximately $35 million. On Feb. 1, 2021, we announced the completion of the conversion to gas of Sundance Unit 6. The Corporation continues to advance the conversion of its Keephills Unit 2 and Keephills Unit 3 for completion later in 2021 and has issued Full Notice to Proceed for both units. In addition, on April 4, 2020, the dual-fuel conversion of Sheerness Unit 2 was completed. The Sheerness facility will receive it's last coal shipment in the first quarter of 2021, with coal stock being actively depleted until the end of 2021. The elimination of coal as a fuel source will reduce future fuel costs and greenhouse gas ("GHG") costs at Sheerness.

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 Clean Energy Investment Plan also includes repowering the steam turbines at Sundance Unit 5 and, potentially, Keephills Unit 1 by installing one or more combustion turbines and heat recovery steam generators, thereby creating highly efficient combined-cycle units. The repowered units are expected to be a 35 per cent to 45 per cent lower capital investment when compared to a new combined-cycle facility, while achieving a similar heat rate. During the first quarter of 2020, we received regulatory approval from the Alberta Utilities Commission ("AUC") and Alberta Environment and Parks for the repowering of Sundance Unit 5 and Keephills Unit 1 into combined-cycle units. During the fourth quarter of 2020, an equipment supply agreement was executed as part of the strategy to repower Sundance Unit 5 into a highly efficient combined cycle unit. The commercial operation date is anticipated in the fourth quarter of 2023. The Sundance Unit 5 repowered combined-cycle unit will have a capacity of approximately 730 MW and is expected to cost approximately $800 million to $825 million, well below a greenfield combined-cycle project. As part of this transaction, we also acquired a long-term PPA for capacity plus energy, including the passthrough of GHG costs, starting in late 2023 with Shell Energy North America (Canada). The Corporation will continue to evaluate the prospect for the repowering of Keephills Unit 1 in 2021 and 2022, as a supply addition to the Alberta market in the 2026 to 2030 time frame.

TransAlta has determined to cease coal-fired operations in Canada by Jan 1, 2022. During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021, and the useful life of the related assets was adjusted to align with the Corporation's conversion to gas plans. As a result, the Corporation announced that Keephills Unit 1 and Sundance Unit 4 will discontinue firing with coal and will only operate on gas effective Jan. 1, 2022. The maximum capability of these units will be reduced to 70 MW and 113 MW, respectively.

As at Dec. 31, 2020, the carrying value of the Highvale mine, including PP&E right-of-use assets and intangible assets, was $373 million. As a result, our cost per tonne of coal will increase as the fixed coal costs will be spread over lower volumes. During the second half of 2020, the increased depreciation expense and our cost per tonne of coal exceeded the net realizable value of the coal inventory and a writedown of $37 million was recognized in fuel, carbon compliance and purchased power. As the Highvale mine moves into the reclamation phase, our anticipated coal consumption is expected to continue to decline, further increasing the cost of coal, and future expected writedowns in fuel costs. In 2020, we started the year with 2.1 million tonnes of coal inventory, during which we mined an additional 2.3 million tonnes and consumed 3.5 million tonnes. We ended the year with approximately 1 million tonnes of coal inventory and we will continue to actively deplete our coal stock as we wind down our mining activity by the end of 2021.

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 that is discussed in more detail later in this section. The Big Level wind project ("Big Level") and Antrim wind project ("Antrim") began commercial operations on Dec. 19, 2019, and Dec, 24, 2019, respectively. The Skookumchuck wind project began commercial operation on Nov. 7, 2020, and was acquired by the Corporation on Nov. 25. 2020. The Windrise wind project ("Windrise") is currently under construction. These projects are underpinned by long-term PPAs with highly creditworthy counterparties. In addition, TransAlta has entered into agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant ("K3"). Please see Note 4(J) for additional details on the current status of the Kaybob cogeneration project.

B. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline") for $83 million. Tidewater Midstream & Infrastructure Ltd.'s (“TMI”) 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 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.

The Pioneer Pipeline is held in a separate entity that is a joint operation with TMI. 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 within the Alberta Thermal segment. 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.

On Oct. 1, 2020, TransAlta announced that it had entered into a definitive Purchase and Sale Agreement providing for the sale of its 50 per cent interest in the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. (“ATCO”) (the "Transaction"). The purchase price of $255 million represents both TransAlta's and TMI's interests. This agreement replaces the previous Purchase and Sale agreement to sell the Pioneer Pipeline to NOVA Gas Transmission Ltd. (“NGTL”) from the second quarter of 2020. ATCO acquired the right to purchase the Pioneer Pipeline through an option agreement with NGTL. Following closing of the Transaction, the Pioneer Pipeline will be integrated into NGTL's and ATCO's Alberta integrated natural gas transmission systems to provide reliable natural gas supply to TransAlta's Sundance and Keephills power generating stations. At Dec. 31, 2020, our interest in the Pioneer Pipeline is included in assets held for sale in the Consolidated Statements of Financial Position.

In addition, TransAlta has entered into incremental long-term firm natural gas delivery transportation agreements with NGTL for 351 TJ per day, bringing the total long-term firm natural gas transportation contracts up to 400 TJ per day by 2023. TransAlta’s current commitments, including the 139 TJ per day supply arrangement with TMI, will remain in place until the closing of the Transaction. The Transaction is subject to customary regulatory approvals and is anticipated to close during the second quarter of 2021.

C. Skookumchuck Wind Project

On April 12, 2019, TransAlta signed an agreement with Southern Power Company, a subsidiary of Southern Company, to have the option to purchase a 49 per cent interest in SP Skookumchuck Investments, LLC ("Skookumchuck") with Southern Power upon the facility's commercial operation date. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas V136 wind turbines. The project began commercial operation on Nov. 7, 2020.

On Nov. 25, 2020, TransAlta completed the acquisition of Skookumchuck. TransAlta's total capital investment was $163 million, with TransAlta paying cash of $86 million (US$66 million) with the remaining $77 million (US$59 million) being funded with tax equity financing. The investment has been classified as a joint venture, as the investment is held in a separate entity and the Corporation has rights to the net assets of Skookumchuck. The Corporation reports its interests in joint arrangements in its consolidated financial statements using the equity method recognizing its share of income (loss) in the Consolidated Statements of Earnings (Loss).

The project has a 20-year PPA with Puget Sound Energy. TransAlta has entered into an definitive agreement with TransAlta Renewables to sell the Corporation's interest in Skookumchuck, which is expected to close in April 2021, as further described below in this section.

D. WindCharger

On Aug. 1, 2020, the WindCharger battery storage project ("WindCharger") was sold to TransAlta Renewables. WindCharger has been operational since Oct. 15, 2020 and is the first utility-scale battery energy storage project in Alberta. The WindCharger project has 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 facility substation. WindCharger stores energy produced by the nearby Summerview II wind facility and discharges it into the Alberta electricity grid at times of peak demand. TransAlta is expected to receive co-funding of almost 50 per cent of the $14 million construction cost from Emissions Reduction Alberta. WindCharger is participating in both the wholesale energy and ancillary services market of the Alberta Electric System Operator ("AESO").

E. Windrise

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was identified by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO subsequently executed a Renewable Electricity Support Agreement with a 20-year term. Windrise 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. Windrise has secured approval for the wind facility and transmission line required to connect the facility to the Alberta grid from the AUC. Construction activities on Windrise continue to advance with all appropriate procedures in place to protect the construction team during the COVID-19 pandemic. However as a result of COVID-19 and related delays in construction, the commercial operation date is expected to occur during the second half of 2021. As of Dec. 31, 2020, Windrise was 78 per cent complete. On Feb. 26, 2021, TransAlta Renewables acquired Windrise from the Corporation as described further below.

F. Acquisition of Wind Development Projects

In 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.

G. EMG International Acquisition

On Nov. 30, 2020, TransAlta acquired a 30 per cent equity interest in EMG to diversify our sustainability offerings to customers while directly supporting our clean energy transition and sustainability goals. Included in the purchase price of US$12 million is an estimated component contingent on EMG realizing certain earnings metrics in 2020 and 2021, following the acquisition. The final contingent amount will be calculated based on actual earnings metrics achieved. EMG is an established company with over 25 years of experience in process wastewater treatment and specializes in the design and construction of high-rate anaerobic digester systems. EMG's wastewater treatment process converts organic waste into a valuable source of renewable energy. Their technology produces a biogas stream that can be used as fuel to generate electricity, displacing energy consumed from higher emitting resources. The investment provides a unique opportunity for TransAlta to leverage its vast expertise in on-site generation to support further advancements by EMG in the waste-to-energy space. This investment will advance the Corporation's presence in the US sustainability and on-site generation markets. The investment has been classified as an Investment in associate, as the Corporation owns 30 per cent of the entity and has representation on the management committee. The Corporation reports its investment in associates in its consolidated financial statements using the equity method recognizing its share of income (loss) in the Consolidated Statement of Earnings (Loss).

H. TransAlta Renewables Acquisitions

On Dec. 23, 2020, the Corporation announced that it had entered into definitive agreements for the acquisition by TransAlta Renewables of its 100 per cent direct interest in the 207 MW Windrise wind project located in the Municipal District of Willow Creek, Alberta; a 49 per cent economic interest in the 137 MW Skookumchuck wind facility located across Thurston and Lewis counties in Washington State; and a 100 per cent economic interest in the 29 MW Ada cogeneration facility located in Ada, Michigan. TransAlta Renewables' acquisition of the Windrise closed on Feb. 26, 2021, and the acquisition of the economic interests in the Ada cogeneration facility and the Skookumchuck wind facility are expected to close in April 2021. The total acquisition value for the portfolio of assets is expected to be $439 million, which includes the remaining construction costs for the Windrise wind project. TransAlta Renewables will fund the acquisition and remaining construction costs with the proceeds from the TEC Hedland financing. Please refer to Note 4(L) for further details.

I. BHP Nickel West Contract Extension

On Oct. 22, 2020, Southern Cross Energy ("SCE"), a subsidiary of the Corporation, replaced and extended its current PPA with BHP Billiton Nickel West Pty Ltd. ("BHP"). SCE is composed of four generation facilities with a combined capacity of 245 MW in the Goldfields region of Western Australia.

The new agreement was effective Dec. 1, 2020, and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038, and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross Facilities for BHP's mining operations located in the Goldfields region of Western Australia. The extension will provide SCE a return on new capital investments, which will be required to support BHP's future power requirements and recently announced emission reduction targets. The amendments within the PPA also provide BHP participation rights in integrating renewable electricity generation, including solar and wind, with energy storage technologies, subject to the satisfaction of certain conditions. Evaluation of renewable energy supply and carbon emissions reduction initiatives under the extended PPA with SCE are underway, including a 18.5MW solar photovoltaic facility supported by a battery energy storage system and a waste heat steam turbine system.

For accounting purposes, the original agreement was accounted for as an operating lease. Under the new PPA, the agreement is now accounted for as a finance lease. As a result, we derecognized net assets of $77 million, which includes balances for PP&E, intangible assets, deferred credits and prepaid expenses. In addition, we recognized a finance lease receivable of $89 million and a gain on asset disposition of $12 million. Subsequent to the transaction, the Corporation incurred additional major maintenance costs in relation to these assets which was recorded as a reduction to the gain on asset disposition.

J. Agreement to Construct and Own a Cogeneration Plant in Alberta

On Oct. 1, 2019, TransAlta and Energy Transfer Canada ("ET Canada" formerly known as SemCAMS Midstream ULC) 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 facility was expected to receive its final regulatory approvals in the second half of the year and begin construction in December 2020. On Sept. 25, 2020, the AUC released a decision in which it approved the construction and operation of the facility, but denied the application for the Industrial System Designation. We are in ongoing commercial and technical discussions with ET Canada relative to the project at K3, or potentially developing a new project at another site owned and/or operated by ET Canada.

K. Acquisition of a Contracted Cogeneration Asset in Michigan

On May 19, 2020, the Corporation closed the previously announced acquisition of a contracted natural-gas-fired cogeneration facility from two private companies for a purchase price of US$27 million. The Ada facility is a 29 MW cogeneration facility ("Ada") in Michigan that is contracted under a PPA and a steam sale agreement for approximately six years with Consumers Energy and Amway.

The fair values of the identifiable assets and liabilities of the acquired entity in the business combination as at the date of acquisition were:

As at May 19, 2020	Fair value recognized on acquisition
Assets	
Net working capital	6
Property, plant and equipment	1
Intangible assets(1)	37
Risk management liabilities (current and long-term)	(5)
Decommissioning provisions	(1)
Total identifiable net assets at fair value	**38**
Cash consideration	**32**
Working capital consideration	**6**
Total purchase consideration transferred	**38**

(1) This relates to the power sales contract acquired and will be amortized over six years.

L. TEC Hedland Pty Ltd. Secures AU$800 Million Financing

On Oct. 22, 2020, TEC Hedland Pty Ltd. ("TEC"), a subsidiary of the Corporation, closed an AU$800 million senior secured note offering ("Offering"), by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The Offering bears interest at 4.07 per cent per annum, payable quarterly and maturing on June 30, 2042, with principal payments starting on Mar. 31, 2022. The Offering has a rating of BBB by Kroll Bond Rating Agency.

TransAlta Renewables has received $480 million (AU$515 million) of the proceeds from the Offering through the redemption of certain intercompany structures. An additional AU$200 million has been loaned to TransAlta Renewables by TransAlta Energy (Australia) Pty Ltd. ("TEA"), which is a subsidiary of TransAlta. The loan bears interest at 4.32 per cent and will be repaid by Oct. 23, 2022 or on demand. The remaining proceeds from the Offering were set aside for required reserves and transaction costs.

TransAlta Renewables used a portion of the proceeds from the redemption and the intercompany loan to repay existing indebtedness on its credit facility and to acquire the asset and economic interests noted above.

M. Strategic Investment by Brookfield

On March 22, 2019, the Corporation 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 through the purchase of exchangeable securities. The securities 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. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in consideration for redeemable, retractable first preferred shares. The proceeds from the first tranche were used to accelerate our conversion to gas program. The Corporation intends to use the proceeds from the second tranche of the financing to advance the Corporation's conversion to gas program, to fund other growth initiatives and for general corporate purposes.

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 25 for further details.

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 collaborate in connection with the operation and maximization of 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 Consolidated 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. As of Dec. 31, 2020, 15,068,900 common shares have been repurchased and $129 million under the normal course issuer bid normal course issuer bid("NCIB") program.

Under the terms of the Investment Agreement, Brookfield committed to purchase TransAlta common shares on the open market to increase its share ownership in TransAlta to not less than nine per cent by May 1, 2021. As of Jan. 8, 2021, Brookfield, through its affiliates, held, owned or had control over an aggregate of 33,845,685 common shares, representing approximately 12.4 per cent of the issued and outstanding common shares, calculated on an undiluted basis. In connection with the Investment, Brookfield is entitled to nominate two directors for election to the Board.

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 Investment Agreement. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter was adjourned due to the COVID-19 pandemic and is now scheduled to proceed to trial for three weeks starting April 19, 2021. Refer to Note 36 for further details.

N. Centralia Unit 1 Retirement

The Corporation owns a two-unit 1,340 MW thermal coal-fired facility in Centralia, Washington in relation to which we have entered into a number of multiple year medium- and short-term energy sales agreements. In 2011, Washington State passed the TransAlta Energy Transition Bill (chapter 180, Laws of 2011) (the "Bill'') allowing the Centralia thermal facility to comply with the State's GHG emissions performance standards by ceasing coal generation in one of its two boilers by the end of 2020 and the other by the end of 2025. The Bill removed restrictions that had previously been imposed on the facility limiting the duration of new contracts from the facility and limiting the technology that the facility would be required to implement for nitrogen oxide controls. Centralia Unit 1 was retired from service effective Dec. 31, 2020.

O. Mothballing of Sundance Units and Sundance Unit 3 Retirement

On March 8, 2019, the Corporation announced that the AESO granted an extension to the mothballing of Sundance Units 3 and 5, which are to remain mothballed until Nov. 1, 2021, extended from April 1, 2020. On July 22, 2020, the Corporation announced that it gave notice to the AESO to retire Sundance Unit 3 effective July 31, 2020. The retirement decision was largely driven by TransAlta's assessment of future market conditions, the age and condition of the unit and our ability to supply energy and capacity from our generation portfolio in Alberta. This decision advances our transition to 100 per cent clean electricity by 2025. The Corporation recognized an impairment charge of approximately $70 million ($52 million after-tax) during the third quarter 2020.

P. COVID-19

The World Health Organization declared a Public Health Emergency of International Concern relating to COVID-19 on Jan. 30, 2020, which they subsequently declared, on March 11, 2020, as a global pandemic. The outbreak of COVID-19 has resulted in governments worldwide enacting emergency measures to constrain the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods, self-isolation, physical and social distancing and the closure of non-essential business, have caused significant disruption to businesses globally, which has resulted in an uncertain and challenging economic environment.

The Corporation continued to operate under its business continuity plan, which focused on ensuring that: (i) employees who could work remotely did so; and (ii) employees who operate and maintain our facilities, and who were not able to work remotely, were able to work safely and in a manner that ensured they remained healthy. During the second and third quarters of 2020, the Corporation successfully brought employees who were working remotely back to the office without compromising health and safety standards. In November 2020, as a result of rising COVID-19 case counts in the Province of Alberta and in light of office attendance restrictions eventually imposed by the Government of Alberta, staff at TransAlta's head office returned to remote work protocols. All of TransAlta's offices and sites follow strict health screening and social distancing protocols with personal protective equipment readily available and in use. Further, TransAlta maintains travel bans aligned to local jurisdictional guidance, enhanced cleaning procedures, revised work schedules, contingent work teams and the reorganization of processes and procedures to limit contact with other employees and contractors on-site.

While our financial results have been impacted by price and demand as a result of COVID-19, all of our facilities continue to remain fully operational and capable of meeting our customers' needs. The Corporation continues to work and serve all of our customers and counterparties under the terms of their contracts. We have not experienced interruptions to service requirements. Electricity and steam supply continue to remain a critical service requirement to all of our customers and have been deemed an essential service in our jurisdictions.

During the second quarter of 2020, the Government of Canada passed the Canada Emergency Wage Subsidy as part of its COVID-19 Economic Response Plan. The program's intent is to support employment by providing expense relief to companies that experienced revenue declines in 2020. In January 2021, TransAlta applied for support under this program and expects to receive $8 million (pre-tax) for application periods in 2020. This represents a portion of the funding that the Corporation is eligible for and will be used in supporting a strategy to add incremental employment within the Corporation.

Q. Normal Course Issuer Bid

2020

On May 26, 2020, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common Shares, representing approximately 7.02 per cent of its public float of common shares as at May 25, 2020. 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 the Corporation is authorized to make purchases under the NCIB commenced on May 29, 2020, and ends on May 28, 2021, 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 228,157 common shares (being 25 per cent of the average daily trading volume on the TSX of 912,630 common shares for the six months ended April 30, 2020) 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, 2020, under the current and previous NCIB, the Corporation purchased and cancelled a total of 7,352,600 common shares at an average price of $8.33 per common share, for a total cost of $61 million. See Note 27 for further details.

2019

On May 27, 2019, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement a 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 4.92 per cent of issued and outstanding common shares as at May 27, 2019.

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 27 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.

R. 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.

In 2019, 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 Highvale mine to the Keephills 3 facility. The Highvale 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 Highvale 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.

S. Termination of the Alberta Sundance Power Purchase Arrangement

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

Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 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.

T. US Wind Projects

On Feb. 20, 2018, 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"). Big Level consists of a 90 MW wind project located in Pennsylvania that has a 15-year PPA with Microsoft Corporation, and 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 March 1, 2018, and Antrim on March 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.

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.

During 2020, TransAlta Renewables subscribed for additional tracking preferred shares in Big Level and Antrim for $72 million (US$52 million). In addition TransAlta Renewables repaid a portion of the total outstanding promissory notes to the Corporation related to the Big Level and Antrim wind projects in the amount of $92 million (US$72 million).

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 $98 million (US$72 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.

U. Kent Hills 3 Wind Project

On Oct. 19, 2018, TransAlta Renewables announced that the Kent Hills 3 expansion was fully operational, bringing total generating capacity of the Kent Hills wind facility to 167 MW.

V. 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 facility 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 facility 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 (US$25 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.

W. TransAlta Renewables Closes $150- Million Share 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 "Share 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 Share 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 Share 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 13 for further details of TransAlta's ownership of TransAlta Renewables.

X. $345 Million Financing Related to the Off-Coal Agreement

On July 20, 2018, the Corporation monetized the payments under OCA 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 in Note 24.

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 asset optimization 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, 2020	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers	141	261	196	90	325	10	—	—	1,023
Revenue from leases(3)	—	—	8	60	55	—	—	—	123
Revenue from derivatives and other trading activities	—	(2)	4	—	(12)	283	122	12	407
Government incentives	1	4	—	—	—	—	—	—	5
Revenue from other(4)	10	66	9	8	251	204	—	(5)	543
Total revenue	**152**	**329**	**217**	**158**	**619**	**497**	**122**	**7**	**2,101**
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	—	25	—	—	23	10	—	—	58
Over time	141	236	196	90	302	—	—	—	965
Total revenue from contracts with customers	**141**	**261**	**196**	**90**	**325**	**10**	**—**	**—**	**1,023**

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details. In addition, during the third quarter of 2020, merchant revenue within this segment was reclassified from revenue from contracts with customers to revenue from other and prior periods were adjusted.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue and other miscellaneous.

Year ended Dec. 31, 2019	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers	142	244	190	87	395	10	—	—	1,068
Revenue from leases(3)	—	—	—	65	65	—	—	—	130
Revenue from derivatives and other trading activities	—	18	2	—	(17)	160	129	4	296
Government incentives	—	8	—	—	—	—	—	—	8
Revenue from other(4)	14	42	17	8	373	401	—	(10)	845
Total revenue	156	312	209	160	816	571	129	(6)	2,347
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	—	27	—	—	41	10	—	—	78
Over time	142	217	190	87	354	—	—	—	990
Total revenue from contracts with customers	142	244	190	87	395	10	—	—	1,068

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details. In addition, during the third quarter of 2020, merchant revenue within this segment was reclassified from revenue from contracts with customers to revenue from other and prior periods were adjusted.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue and other miscellaneous.

Year ended Dec. 31, 2018	Hydro	Wind and Solar	North American Gas[1]	Australian Gas	Alberta Thermal[2]	Centralia[2]	Energy Marketing	Corporate	Total
Revenues from contracts with customers	132	206	206	91	517	9	—	—	1,161
Revenue from leases[3]	7	27	—	68	68	—	—	—	170
Revenue from derivatives and other trading activities	—	(20)	4	—	(1)	115	67	—	165
Government incentives	—	16	—	—	—	—	—	—	16
Revenue from other[4]	17	53	22	6	328	318	—	(7)	737
Total revenue	156	282	232	165	912	442	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	—	18	—	—	38	9	—	—	65
Over time	132	188	206	91	479	—	—	—	1,096
Total revenue from contracts with customers	132	206	206	91	517	9	—	—	1,161

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details. In addition, during the third quarter of 2020, merchant revenue within this segment was reclassified from revenue from contracts with customers to revenue from other and prior periods were adjusted.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue and other miscellaneous.

B. Contract Liabilities

The Corporation has recognized the following revenue-related contract liabilities:

Contract liabilities	2020	2019
Balance, beginning of the year	**15**	88
IFRS 16 transition adjustments[1]	**—**	15
Amounts transferred to revenue included in opening balance	**(1)**	(10)
Consideration received	**1**	5
Increases due to interest accrued and expensed during the period	**—**	5
Contract termination associated with the purchase of Keephills 3 (Note 4(R))	**—**	(88)
Consideration paid	**2**	—
Performance obligations satisfied	**(2)**	—
Balance, end of year	**15**	15
Current portion	**1**	1
Long-term portion	**14**	14

(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.

The opening contract liabilities in 2019 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 in 2019 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, 2020, and 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.

Hydro

At Dec. 31, 2020, the Corporation's PPA with the Balancing Pool to provide the capacity of 12 hydro facilities throughout the province of Alberta concluded. Future production will be sold into the merchant market. The Corporation has contracts for blackstart services at specific hydro facilities, which will conclude at the end of 2030. The Corporation also has 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, 2020, are approximately $31 million, which the Corporation expects to recognize approximately $8 million in 2021 and approximately $2 million to $3 million annually from 2022-2030.

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.

Wind and Solar

At Dec. 31, 2020, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind facilities 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 over 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 purchasers 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, 2020, are approximately $13 million, of which the Corporation expects to recognize between approximately $2 million to $5 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.

North American Gas
At Dec. 31, 2020, the Corporation has contracts with customers to deliver energy services from one of its gas facilities 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 facility, 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, 2020, the Corporation had contracts with customers to deliver steam, hot water and chilled water from one of its other gas facilities 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.

The Corporation's contract with its customer for provision of steam and electricity output at its Alberta cogeneration facility, effective Jan. 1, 2020 through Dec. 31, 2029, is considered an operating lease resulting in some revenues being classified for accounting purposes as variable lease revenues. Other revenue streams are based on cost-recovery mechanisms and thus are variable in nature and are considered to be fully constrained and excluded from these disclosures.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2020, are approximately $13 million in total, of which the Corporation expects to recognize between approximately $4 million to $5 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 and the United States; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas
At Dec. 31, 2020, the Corporation has PPAs with customers to deliver electricity from its gas facilities located in Australia. 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 2026 to 2042.

One of the Corporation's PPA with its customer to deliver electricity from its gas facilities is considered a finance lease resulting in some revenues being classified for accounting purposes as finance lease income. The Corporation also earns revenues from providing operation and maintenance services for the facility for a fixed monthly fee. Pricing is subject to periodic review under the PPA and subject to escalation to reflect inflation out to the end of the contract in 2038. Other revenue streams are based on cost-recovery mechanisms and thus are variable in nature and considered to be fully constrained and excluded from these disclosures.

Estimated future revenues related to the remaining performance obligations for these contracts as at Dec. 31, 2020, are approximately $2,594 million, of which the Corporation expects to recognize approximately $203 million in total over the next two fiscal years and on average, between approximately $100 million to $126 million annually thereafter for the duration of the remaining contract.

Alberta Thermal

At Dec. 31, 2020, the Corporation's PPAs with the Balancing Pool for capacity and electricity from two of its coal facilities concluded. Future production will be sold into the merchant market.

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal facilities. 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, 2020, are approximately $336 million, of which the Corporation expects to recognize on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

Centralia

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.

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2020**		2019		2018	
	Fuel, carbon compliance and purchased power	**Operations, maintenance and administration**	Fuel, carbon compliance and purchased power	Operations, maintenance and administration	Fuel, carbon compliance and purchased power	Operations, maintenance and administration
Fuel and carbon compliance	**574**	**—**	669	—	656	—
Coal inventory writedown (Note 17)	**37**	**—**	—	—	—	—
Purchased power	**163**	**—**	246	—	210	—
Mine depreciation	**144**	**—**	119	—	136	—
Salaries and benefits	**50**	**235**	52	228	98	245
Other operating expenses	**—**	**237**	—	247	—	270
Total	**968**	**472**	1,086	475	1,100	515

7. Asset Impairment 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. 2020

Sundance Unit 3

In the third quarter of 2020, the Corporation recognized an impairment on Sundance Unit 3 in the amount of $70 million in the Alberta Thermal segment, due to the Corporation's decision to retire the unit (see Note 4(O)). Previously, the Corporation had expected Sundance Unit 3 to remain mothballed until November 2021. As there were no estimated future cash flows from power generation expected to be derived from the unit, the unit was removed from the Alberta merchant CGU and immediately written down to the recoverable value of the scrap materials.

BC Hydro Facility

In the third quarter of 2020, the Corporation recorded an impairment of $2 million in the Hydro segment, due to a review of water resources that resulted in a revision to the forecasted production at a BC hydro facility. The impairment assessment was based on fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The resulting fair value measurement is categorized as a Level III fair value measurement. The key assumptions impacting the determination of fair value are electricity production and sales prices, which are subject to measurement uncertainty.

Centralia Land

In the fourth quarter of 2020, the Corporation recognized an impairment of $9 million (US$7 million) in the Centralia segment due to a decrease in the fair value of the land determined through a third-party appraiser.

In addition to the asset impairments noted above, a net asset impairment of $3 million was recognized for changes in the decommissioning and restoration liabilities related to the Centralia mine and Sundance Unit 1, which are no longer operating and have reached the end of their useful lives (see Note 23).

B. 2019

Centralia Thermal Facility

In 2012, the Corporation recorded an impairment of $347 million relating to the Centralia thermal facility CGU. As part of the annual impairment test, the Corporation considers possible indicators of impairment at the Centralia thermal facility CGU. In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia thermal facility 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 Centralia 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 ("MOA") for coal transition established with the State of Washington. The valuation period includes cash flows until the decommissioning of the facility 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. At the end of 2019, the Corporation's 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)(III) and 23 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 Alberta Thermal segment and accordingly wrote the assets down to net realizable value, resulting in an impairment charge of $15 million.

C. 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(V)). 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 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 18 and 20).

D. Project Development Costs

During 2020, the Corporation wrote off nil (2019 — $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 2020, the Southern Cross Energy facilities are as follows:

As at Dec. 31	**2020**		2019	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**63**	**56**	20	20
Second to fifth years inclusive	**169**	**126**	80	74
More than five years	**100**	**82**	120	97
	332	**264**	220	191
Less: unearned finance lease income	**68**	**—**	29	—
Total finance lease receivables	**264**	**264**	191	191

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 14)	**36**	15
Long-term portion of finance lease receivables	**228**	176
	264	191

9. Net Other Operating Income

Net other operating income includes the following:

Year ended Dec. 31	2020	2019	2018
Coal supply agreement	**29**	—	—
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Insurance recoveries	**—**	(10)	(7)
Other expenses	**—**	1	—
Net other operating income	**(11)**	(49)	(47)

A.Onerous Contract Provision for Coal Supply Agreement

During the fourth quarter of 2020, an onerous contract provision of $29 million was recognized as a result of a decision to accelerate our plans to eliminate coal as a fuel source by the end of 2021 at the Sheerness facility. The last coal shipment is expected to be received during the first quarter of 2021, while payments required under the contract will continue until 2025.

B. 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 did not impact the payments received. Refer to Note 4(R) 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), which commenced Jan. 1, 2017, and will terminate 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(X) and 24 for further details.

C. Insurance Recoveries

There were no insurance recoveries in 2020.

During 2019, the Corporation received $10 million in insurance recoveries, which related to insurance proceeds for tower fires at Wyoming 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 and a $1 million claim related to equipment repairs within Alberta Thermal.

10. Investments

The Corporation's investments in joint ventures and associates that are accounted for using the equity method consist of its investments in Skookumchuck and EMG.

The change in investments is as follows:

	Skookumchuck	EMG	Total
Balance, Dec. 31, 2019	—	—	**—**
Contributions(1)	86	16	**102**
Equity income	1	—	**1**
Change in foreign exchange rates	(2)	(1)	**(3)**
Balance, Dec. 31, 2020	**85**	**15**	**100**

(1) Contributions were paid in US dollars and were US$66 million for Skookumchuck and US$12 million for EMG, including contingent consideration.

Summarized financial information on the results of operations relating to the Corporation's pro-rata interests in Skookumchuck and EMG is as follows:

Year ended Dec. 31	2020
Results of operations	
Revenues	3
Expenses	(2)
Proportionate share of net earnings	1

On Nov. 25, 2020, TransAlta purchased a 49 per cent interest in Skookumchuck, a 136.8 MW wind facility located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas 136 wind turbines. Summarized financial information relating to 100 per cent of Skookumchuck, including adjustments for the application of consistent accounting policies and the Corporation's purchase price adjustments, is as follows:

Year ended Dec. 31	2020
Revenues	6
Depreciation and amortization	2
Interest expense	1
Net earnings	3
Other comprehensive loss	–
Total comprehensive loss	3

As at Dec. 31	2020
Current assets	6
Non-current assets	382
Current liabilities	(65)
Non-current liabilities	(150)
Net assets	173
Additional items included above	
Cash and cash equivalents	1
Current financial liabilities[1]	(27)
Non-current financial liabilities[1]	(147)

(1) Excludes trade and other payables and provisions.

A reconciliation of the carrying amount to the Corporation's 49 per cent interest in the Skookumchuck is as follows:

As at Dec. 31	2020
Net assets	173
Less: 51 per cent of Skookumchuck net assets not owned by the Corporation	(88)
Net investment	85

Skookumchuck's ability to make distributions to its owners, including the Corporation, is dependent on available cash flow and is restricted by covenants and conditions, including principal and interest funding requirements imposed by the tax equity financing agreements.

Skookumchuck's approximate future payments under contractual commitments are as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Long-term service agreements[1]	1	1	1	1	1	28	33

(1) Refer to Note 36 for further details on long-term service agreements.

11. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2020	2019	2018
Interest on debt	**158**	161	184
Interest on exchangeable securities (Note 25)	**34**	20	—
Interest income	**(10)**	(13)	(11)
Capitalized interest (Note 18)	**(8)**	(6)	(2)
Loss on redemption of bonds (Note 24)	**—**	—	24
Interest on lease liabilities	**8**	4	3
Credit facility fees, bank charges and other interest	**18**	15	13
Tax shield on tax equity financing (Note 24)(1)	**1**	(35)	—
Interest on line loss rule proceeding (Note 36(I)(I))	**5**	—	—
Other(2)	**2**	10	15
Accretion of provisions (Note 23)	**30**	23	24
Net interest expense	**238**	179	250

(1) Relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim 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 2020, other interest expense included approximately nil (2019 — $5 million, 2018 — $7 million) 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.

12. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2020	2019	2018
Earnings (loss) before income taxes	**(303)**	193	(96)
Net earnings (loss) attributable to non-controlling interests not subject to tax	**2**	(26)	(19)
Adjusted earnings (loss) before income taxes	**(301)**	167	(115)
Statutory Canadian federal and provincial income tax rate (%)	**24.5%**	26.5%	26.8%
Expected income tax expense (recovery)	**(74)**	44	(31)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**3**	5	(3)
Deferred income tax expense related to temporary difference on investment in subsidiaries	**9**	—	—
Writedown (reversal of writedown) of deferred income tax assets	**8**	(9)	27
Statutory and other rate differences	**(7)**	(31)	—
Other	**11**	8	1
Income tax expense (recovery)	**(50)**	17	(6)
Effective tax rate (%)	**17%**	10%	5%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2020	2019	2018
Current income tax expense	**35**	35	28
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(95)**	22	(61)
Deferred income tax expense related to temporary difference on investment in subsidiary	**9**	—	—
Deferred income tax recovery resulting from changes in tax rates or laws(1)	**(7)**	(31)	—
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets(2)	**8**	(9)	27
Income tax expense (recovery)	**(50)**	17	(6)

Year ended Dec. 31	2020	2019	2018
Current income tax expense	**35**	35	28
Deferred income tax recovery	**(85)**	(18)	(34)
Income tax expense (recovery)	**(50)**	17	(6)

(1) In 2020 the Corporation recognized a deferred income tax recovery of $7 million (2019 —$31 million) related to a decrease in the Alberta corporate tax rate from 11 per cent to 8 per cent. The tax decrease was originally scheduled as follows: 11 per cent effective July 1, 2019, 10 per cent effective Jan. 1, 2020, 9 per cent effective Jan. 1, 2021, and 8 per cent effective Jan. 1, 2022. The Government of Alberta enacted the rate to decrease to 8 per cent effective Dec. 9, 2020.

(2) During the year ended Dec. 31, 2020, the Corporation recorded a writedown of deferred tax assets of $8 million (2019 — $9 million writedown reversal, 2018 — $27 million writedown). In the current year additional deferred tax assets were created from the recognition of other comprehensive losses in the US. The deferred income tax assets mainly relate 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.

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	2020	2019	2018
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(23)**	6	(12)
Net actuarial gains (losses)	**(3)**	(7)	5
Income tax expense reported in equity	**(26)**	(1)	(7)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2020	2019
Net operating loss carryforwards[1]	**469**	494
Future decommissioning and restoration costs	**140**	122
Property, plant and equipment	**(717)**	(828)
Risk management assets and liabilities, net	**(107)**	(141)
Employee future benefits and compensation plans	**62**	56
Interest deductible in future periods	**22**	42
Foreign exchange differences on US-denominated debt	**31**	40
Other deductible temporary differences	**2**	4
Net deferred income tax liability, before writedown of deferred income tax assets	**(98)**	(211)
Writedown of deferred income tax assets	**(247)**	(243)
Net deferred income tax liability, after writedown of deferred income tax assets	**(345)**	(454)

(1) Net operating losses expire between 2029 and 2039.

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

As at Dec. 31	2020	2019
Deferred income tax assets[1]	**51**	18
Deferred income tax liabilities	**(396)**	(472)
Net deferred income tax liability	**(345)**	(454)

(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, 2020, the Corporation had recognized a net liability of nil (2019 – $1 million) related to uncertain tax positions.

13. 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, 2020
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.9% - 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 dual-fuel generating 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 facility located in New Brunswick.

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 could elect to automatically reinvest monthly dividends into additional common shares of the Corporation. The Corporation does not participate in the DRIP.

In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends. The dividend paid on Oct. 30, 2020, to shareholders of record on Oct. 15, 2020, was the last dividend payment eligible for reinvestment by participating shareholders. Subsequent dividends will be paid only in cash.

As a result of the DRIP and the Share Offering described in Note 4(W), 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**
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
April 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
Jan. 1, 2020 to Mar. 31, 2020	60.3	60.3
April 1, 2020 to June 30, 2020	60.2	60.2
July 1, 2020 to Dec. 31, 2020	60.1	60.1

Year ended Dec. 31	**2020**	2019	2018
Revenues	**436**	446	462
Net earnings	**97**	183	241
Total comprehensive income	**223**	138	281
Amounts attributable to the non-controlling interests:			
Net earnings	**40**	73	94
Total comprehensive income	**90**	56	110
Distributions paid to non-controlling interests	**80**	69	79

As at Dec. 31	**2020**	2019
Current assets	**743**	293
Long-term assets	**2,913**	3,409
Current liabilities	**(364)**	(152)
Long-term liabilities	**(987)**	(1,237)
Total equity	**(2,305)**	(2,313)
Equity attributable to non-controlling interests	**(948)**	(941)
Non-controlling interests' share (per cent)	**39.9**	39.6

B. TA Cogen

Year ended Dec. 31	2020	2019	2018
Results of operations			
Revenues	**146**	181	185
Net earnings (loss)	**(13)**	43	29
Total comprehensive income (loss)	**(13)**	43	29
Amounts attributable to the non-controlling interest:			
Net earnings (loss)	**(6)**	21	14
Total comprehensive income (loss)	**(6)**	21	14
Distributions paid to Canadian Power Holdings Inc.	**17**	37	86

As at Dec. 31	2020	2019
Current assets	**69**	41
Long-term assets	**323**	328
Current liabilities	**(78)**	(27)
Long-term liabilities	**(37)**	(19)
Total equity	**(277)**	(323)
Equity attributable to Canadian Power Holdings Inc.	**(136)**	(160)
Non-controlling interest share (per cent)	**49.99**	49.99

14. Trade and Other Receivables

As at Dec. 31	2020	2019
Trade accounts receivable	**488**	399
Collateral paid (Note 16)	**49**	42
Current portion of finance lease receivables (Note 8)	**36**	15
Income taxes receivable	**10**	6
Trade and other receivables	**583**	462

15. 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, 2020

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	–	–	703	703
Restricted cash	–	–	71	71
Trade and other receivables	–	–	583	583
Long-term portion of finance lease receivable	–	–	228	228
Risk management assets				
Current	102	69	–	171
Long-term	471	50	–	521
Other assets (Note 22)	–	–	52	52
Financial liabilities				
Accounts payable and accrued liabilities	–	–	599	599
Dividends payable	–	–	59	59
Risk management liabilities				
Current	10	84	–	94
Long-term	–	68	–	68
Credit facilities, long-term debt and lease liabilities[2]	–	–	3,361	3,361
Exchangeable securities (Note 25)	–	–	730	730

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

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 receivables	–	–	176	176
Risk management assets				
Current	71	95	–	166
Long-term	607	33	–	640
Other assets (Note 22)	–	–	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 lease liabilities[2]	–	–	3,212	3,212
Exchangeable securities (Note 25)	–	–	326	326

(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 primarily calculated within the Corporation's energy trading risk management system. These calculations are 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, 2020**			
Description	**Base fair value**	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Range**	**Reasonable possible change**
Long-term power sale – US	**598**	**+35** / **-59**	Long-term price forecast	Illiquid future power prices (per MWh)	US$24 to US$32	Price decrease of US$3 or price increase of US$5
Coal transportation – US	**(16)**	**+3** / **-5**	Numerical derivative valuation	Illiquid future power prices (per MWh)	US$24 to US$32	Price decrease of US$3 or price increase of US$5
				Volatility	15% to 40%	80% to 120%
				Rail rate escalation	US$21 to US$24	zero to 4%
Full requirements – Eastern US	**11**	**+3** / **-3**	Historical bootstrap	Volume		95% to 105%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	**(29)**	**+22** / **-22**	Long-term price forecast	Illiquid future power prices (per MWh)	US$35 to US$52	Price increase or decrease of US$6
				Illiquid future REC prices (per unit)	US$11	Price increase or decrease of US$1
Others	**(4)**	**+5** / **-5**				

As at			Dec. 31, 2019			
Description	Base fair value	Sensitivity	Valuation technique	Unobservable input	Range	Reasonable possible change
Long-term power sale – US	737	+46 / -139	Long-term price forecast	Illiquid future power prices (per MWh)	US$20 to US$28	Price decrease of US$3 or a price increase of US$9
Structured products – Eastern US	7	+2 / -2	Option valuation techniques, historical bootstrap and historical price regression analysis	Basis relationship	91% to 112%	4% to 6%
				Non-standard shape factors	63% to 116%	4% to 10%
Full requirements –Eastern US	10	+3 / -3	Historical bootstrap	Volume		95% to 105%
				Cost of supply		(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	(28)	+20 / -20	Long-term price forecast	Illiquid future power prices (per MWh)	US$38 to US$60	Price increase or decrease of US$6
				Illiquid future REC prices (per unit)	US$9	Price increase or decrease of US$1
Others	(6)	+8 / -8				

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 2022, 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.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2019, to Dec. 31, 2020, the base fair value and the sensitivity values have decreased by approximately $14 million and $1 million, respectively.

ii. Structured Products – Eastern US

The Corporation has structured fixed priced power in the eastern United States. Under these contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. As at Dec. 31, 2020, the Corporation did not have any material open positions on structured fixed priced power 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.

iii. Coal Transportation - US

The Corporation has a coal rail transport agreement that includes an upside sharing mechanism, with a contract start date of Jan. 1, 2021, and extending until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

The key unobservable inputs used in the valuation include non-liquid power prices, option volatility and rail rate escalation. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

For periods beyond 2022, 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). Option volatility and rail rate escalation ranges have been determined based on historical data and professional judgement.

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.

v. Long-Term Wind Energy Sale – Eastern US

In relation to the Big Level, 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 non-liquid forward prices for power and RECs.

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, 2020, are as follows: Level I – $13 million net liability (Dec. 31, 2019 – $3 million net liability), Level II – $27 million net liability (Dec. 31, 2019 – $9 million net asset) and Level III – $582 million net asset (Dec. 31, 2019 – $686 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2020, are primarily attributable to contract settlements, unfavourable changes in market prices and unfavourable changes in foreign exchange rates.

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, 2020 and 2019, respectively:

	Year ended Dec. 31, 2020			Year ended Dec. 31, 2019		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**678**	**8**	**686**	689	6	695
Changes attributable to:						
Market price changes on existing contracts	**(18)**	**3**	**(15)**	77	8	85
Market price changes on new contracts	**—**	**7**	**7**	—	14	14
Contracts settled	**(71)**	**(10)**	**(81)**	(57)	(19)	(76)
Change in foreign exchange rates	**(16)**	**1**	**(15)**	(31)	(1)	(32)
Transfers into (out of) Level III	**—**	**—**	**—**	—	—	—
Net risk management assets at end of period	**573**	**9**	**582**	678	8	686
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**(34)**	**—**	**(34)**	46	—	46
Total gains included in earnings before income taxes	**71**	**11**	**82**	57	21	78
Unrealized gains included in earnings before income taxes relating to net assets held at period end	**—**	**1**	**1**	—	2	2

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 liability fair value of $12 million as at Dec. 31, 2020 (Dec. 31, 2019 – $4 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the year ended Dec. 31, 2020, are primarily attributable to favorable 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)**
Exchangeables securities – Dec. 31, 2020	**—**	**769**	**—**	**769**	**730**
Long-term debt – Dec. 31, 2020	**—**	**3,480**	**—**	**3,480**	**3,227**
Exchangeable securities – Dec. 31, 2019	—	342	—	342	326
Long-term debt – Dec. 31, 2019	—	3,157	—	3,157	3,070

(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, restricted cash, 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 22) 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 15 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	**2020**	2019	2018
Unamortized net gain at beginning of year	**9**	49	105
New inception gains (losses)(1)	**(13)**	3	(14)
Change in foreign exchange rates	**—**	—	5
Amortization recorded in net earnings during the year	**(29)**	(43)	(47)
Unamortized net gain (loss) at end of year(2)	**(33)**	9	49

(1) During 2020, the Corporation entered into a coal rail transportation agreement that includes an upside sharing mechanism. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.
(2) During 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day 1 forward price curve at inception of the contract.

16. 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, 2020

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**101**	**(11)**	**90**
Long-term	**471**	**(19)**	**452**
Net commodity risk management assets (liabilities)	**572**	**(30)**	**542**
Other			
Current	**(9)**	**(4)**	**(13)**
Long-term	**—**	**1**	**1**
Net other risk management liabilities	**(9)**	**(3)**	**(12)**
Total net risk management assets (liabilities)	**563**	**(33)**	**530**

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

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	2020				2019			
	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	**120**	**69**	**(132)**	**(104)**	316	631	(191)	(100)
Gross amounts set-off	**(69)**	**(10)**	**69**	**10**	(140)	(42)	140	42
Net amounts as included in the Consolidated Statements of Financial Position	**51**	**59**	**(63)**	**(94)**	176	589	(51)	(58)

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 thermal facility 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, 2020, associated with the Corporation's proprietary trading activities was $1 million (2019 — $1 million, 2018 — $2 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and 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, 2020, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $12 million (2019 — $25 million, 2018 — $18 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, 2020, associated with these transactions was $15 million (2019— $8 million, 2018 — $13 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	**2020**		2019	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*[(1)]	**95**	**—**	222	—

(1) Excludes the long-term power sale - US contract. For further details on this contract, refer to Note 15(B)(I)(c)(i).

During 2020, unrealized pre-tax gains of $1 million (2019 — $1 million, 2018 — $4 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	**2020**		2019	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**12,944**	**8,258**	16,097	7,204
Natural gas *(GJ)*	**23,035**	**177,448**	38,062	55,023
Transmission *(MWh)*	**—**	**1,578**	—	1,818
Emissions *(MWh)*	**1,831**	**2,112**	184	138
Emissions *(tonnes)*	**2,160**	**2,365**	2,436	2,446

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 represent 7 per cent of the Corporation’s debt as at Dec. 31, 2020 (2019 – 11 per cent). Interest rate risk is managed with the use of derivatives. The Corporation's outstanding interest rate derivative instruments are as follows.

At Dec. 31, 2020, the Corporation had interest rate swap agreements in place with a notional amount of US$150 million whereby the Corporation receives a variable rate of interest equal to the three-month LIBOR rate and pays interest at a fixed rate equal to 0.94 per cent on the notional amount. The swap is being used to hedge interest rate exposure on a highly probable future US$400 million fixed rate debt issuance.

At Dec. 31, 2020, the Corporation had a bond lock agreement in place with a notional amount of $75 million whereby on the pricing date, if the difference between the underlying 5.75 per cent Government of Canada bond and the forward bond price of $150 million (forward yield 1.20 per cent) is positive, the Corporation receives settlement. If the difference is negative, the Corporation pays settlement. The swap is being used to hedge interest rate exposure on a highly probable future $150 million fixed rate debt issuance.

There were no interest rate derivative instruments outstanding in 2019 or 2018.

IBOR reform could impact interest rate risk with respect to the Corporation's credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The facility references LIBOR for US dollar drawings and Canadian Dollar Offer Rate ("CDOR") for Canadian dollar drawings: in addition the non-recourse bond references the three month CDOR. To date, no US dollar drawings have been made on the facility and there is currently a plan to discontinue the six-twelve month CDOR, which does not impact the facility or the non-recourse bond.

Outstanding forward starting interest rate swaps in both Canadian and US dollars should not be affected as they are set to settle in 2021 prior to any IBOR changes being made. The Corporation is monitoring the reform and does not expect any material impacts.

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.

The Corporation's 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 a combination of interest expense on our Australian-dollar denominated debt and forward foreign exchange contracts.

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 if 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 (2019 — US$370 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	2020			2019			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures							
CAD71	**USD54**	**(2)**	**2021**	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 US and Australian 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.

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	2020			2019			
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							
AUD197	**CAD181**	**(14)**	**2021-2024**	AUD286	CAD266	—	2020 - 2023
USD47	**CAD72**	**9**	**2021-2024**	USD108	CAD139	(4)	2020 - 2023
AUD4	**USD3**	**—**	**2021**				
CAD1	**EUR1**	**—**	**2021**				
Foreign exchange forward contracts – foreign-denominated debt							
CAD191	USD150	2	**2022**	CAD191	USD150	6	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 (2019 — three cent, 2018 — 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	2020		2019		2018	
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	**(8)**	**1**	(18)	2	(13)	—
AUD	**(4)**	**—**	(6)	—	(7)	—
Total	**(12)**	**1**	(24)	2	(20)	—

(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, 2020:

	Investment grade *(Per cent)*	Non-investment grade *(Per cent)*	Total *(Per cent)*	Total amount
Trade and other receivables[1]	92	8	**100**	**583**
Long-term finance lease receivable	100	—	**100**	**228**
Risk management assets[1]	93	7	**100**	**692**
Loan receivable[2]	—	100	**100**	**52**
Total				**1,555**

(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 22 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 segment historical rates of default of trade receivables as well as incorporating 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, 2020.

The Corporation's maximum exposure to credit risk at Dec. 31, 2020, 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, 2020, was $22 million (2019 — $5 million).

Amidst the current economic conditions resulting from the COVID-19 pandemic, TransAlta has implemented the following additional measures to monitor its counterparties for changes in their ability to meet obligations:

- Daily monitoring of events impacting counterparty creditworthiness and counterparty credit downgrades;
- Weekly oversight and follow-up, if applicable, of accounts receivables; and
- Review and monitoring of key suppliers, counterparties and customers (i.e., off-takers).

As needed, additional risk mitigation tactics will be taken to reduce the risk to TransAlta. These risk mitigation tactics may include, but are not limited to, immediate follow-up on overdue amounts, adjusting payment terms to ensure a portion of funds are received sooner, requiring additional collateral, reducing transaction terms and working closely with impacted counterparties on negotiated solutions.

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, 2020, TransAlta maintains an investment grade rating from one credit rating agency and below investment grade ratings from two credit rating agencies. Between 2021 and 2023, the Corporation has approximately $1 billion of debt maturing, comprised of approximately $631 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We expect to refinance the debt maturing in 2022.

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:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Accounts payable and accrued liabilities	599	—	—	—	—	—	599
Long-term debt(1)	96	626	277	119	136	2,010	3,264
Exchangeable securities(2)	—	—	—	—	750	—	750
Commodity risk management (assets) liabilities	(92)	(87)	(131)	(131)	(103)	2	(542)
Other risk management (assets) liabilities	14	—	1	(2)	—	(1)	12
Lease liabilities(3)	(5)	6	5	5	5	118	134
Interest on long-term debt and lease liabilities(4)	161	153	126	119	113	893	1,565
Interest on exchangeable securities(2, 4)	53	52	53	52	—	—	210
Dividends payable	59	—	—	—	—	—	59
Total	**885**	**750**	**331**	**162**	**901**	**3,022**	**6,051**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025. Refer to Note 25 for further details.
(3) Lease liabilities include a lease incentive of $13 million, expected to be received in 2021.
(4) 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					
	2021	2022	2023	2024	2025	2026 and thereafter
Cash flow hedges[1]						
Foreign currency forward contracts						
Notional amount ($ millions)						
CAD/USD	54	—	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7648	—	—	—	—	—
Commodity derivative instruments						
Electricity						
Notional amount (thousands MWh)	3,424	3,329	3,329	3,338	2,628	—
Average Price ($ per MWh)	69.51	71.91	73.72	75.56	77.44	—

(1) The interest rate swaps detailed above both settle in 2021.

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, 2020	**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	**16 MMWh**	**573**	**Risk management assets**	**(33)**
Interest rate risk				
Cash flow hedges				
Interest rate swap	**USD150**	**(3)**	**Risk management liabilities**	**3**
Interest rate swap	**CAD75**	**(4)**	**Risk management liabilities**	**4**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD472**	**Credit facilities, long-term debt and lease liabilities**	**11**

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 lease liabilities	21

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31	2020		2019	
	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	**(33)**	**417**	47	527
Interest rate risk				
Cash flow hedges				
Interest expense on long-term debt	**7**	**19**	—	—
	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]
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**11**	**(21)**	21	(21)

(1) Included in AOCI.

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. 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, 2020			
		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	**41**	Revenue	**(137)**	Revenue	**—**
Foreign exchange forwards on project hedges	**(1)**	Property, plant and equipment	**—**	Foreign exchange (gain) loss	**—**
Forward starting interest rate swaps	**(12)**	Interest expense	**(4)**	Interest expense	**—**
OCI impact	**28**	**OCI impact**	**(141)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $72 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, 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	—

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	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2020, the Corporation recognized a net unrealized gain of $43 million (2019 — gain of $33 million, 2018 — loss of $29 million) related to commodity derivatives.

For the year ended Dec. 31, 2020, a gain of $11 million (2019 — gain of $24 million, 2018 —gain of $3 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized loss of $2 million (2019 — gains of $6 million, 2018 — gains of $4 million) and net realized gains of $13 million (2019 — gains of $18 million, 2018 — losses of $1 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2020, the Corporation provided $49 million (2019 – $42 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, 2020, the Corporation held nil (2019 – $3 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, 2020, the Corporation had posted collateral of $163 million (Dec. 31, 2019 – $112 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 $85 million (Dec. 31, 2019 – $51 million) of collateral to its counterparties.

17. 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.

In the third quarter of 2020, the Corporation adjusted the useful life of its Highvale mine assets to align with the Corporation's conversion to gas plans. The standard cost of coal has increased as a result of the increased depreciation costs, in addition to reduced coal consumption. As the cost is not expected to be recovered based on current power pricing, the Corporation recognized a $37 million writedown to net realizable value on its internally produced coal inventory for the year ended Dec. 31, 2020.

The components of inventory are as follows:

As at Dec. 31	**2020**	2019
Parts and materials	**107**	108
Coal	**83**	130
Deferred stripping costs	**8**	6
Natural gas	**2**	3
Purchased emission credits[1]	**38**	4
Total	**238**	251

(1) Purchased emissions credits increased due to trading and compliance credits purchased, including those for Alberta compliance under the Technology Innovation and Emissions Reduction program.

The change in inventory is as follows:

Balance, Dec. 31, 2018	242
Net addition	12
Change in foreign exchange rates	(3)
Balance, Dec. 31, 2019	251
Net addition	**26**
Writedowns	**(37)**
Change in foreign exchange rates	**(2)**
Balance, Dec. 31, 2020	**238**

No inventory is pledged as security for liabilities.

The Corporation purchases emissions credits and also generates emissions credits from its Wind and Solar and Hydro segments. Emission credits generated from our business have no recorded book value but will be used to offset other emissions obligations in the future, resulting in reduced fuel compliance costs. At Dec. 31, 2020, we currently hold 1,434,761 purchased emission credits (2019 — 388,155) recorded at $38 million (2019 — $4 million) and approximately 502,653 (2019 — 411,115) emission credits with no recorded book value.

18. 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, 2018	94	5,937	1,964	3,286	1,338	200	383	13,202
Adjustments on implementation of IFRS 16	—	—	—	(7)	(101)	—	—	(108)
Additions	—	—	—		—	407	115	522
Acquisitions (Note 4(R) and 4(T))[2]	—	300	—	—	—	139	—	439
Disposals[3]	(2)	(389)	(260)	—	(34)	—	(19)	(704)
(Impairment) reversals (Note 7)	—	448	—	(2)	(15)	—	—	431
Revisions and additions to decommissioning and restoration costs (Note 23)	—	(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[4]	—	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
Additions	**—**	**—**	**—**	**—**	**—**	**478**	**8**	**486**
Acquisitions (Note 4(K))	**—**	**—**	**1**	**—**	**—**	**—**	**—**	**1**
Disposals	**(2)**	**(1)**	**—**	**—**	**—**	**—**	**(2)**	**(5)**
Impairment (Note 7)	**(9)**	**(69)**	**—**	**(2)**	**—**	**—**	**(1)**	**(81)**
Revisions and additions to decommissioning and restoration costs (Note 23)	**—**	**21**	**(11)**	**8**	**76**	**—**	**—**	**94**
Retirement of assets	**—**	**(35)**	**(12)**	**(7)**	**(3)**	**—**	**(1)**	**(58)**
Change in foreign exchange rates	**(1)**	**(37)**	**45**	**(14)**	**(2)**	**—**	**6**	**(3)**
Transfers[4]	**17**	**142**	**(263)**	**33**	**(29)**	**(211)**	**(120)**	**(431)**
As at Dec. 31, 2020	**96**	**6,137**	**1,431**	**3,592**	**1,268**	**495**	**379**	**13,398**
Accumulated depreciation								
As at Dec. 31, 2018	—	3,765	1,128	1,161	830	—	154	7,038
Adjustments on implementation of IFRS 16	—	—	—	(3)	(43)	—	—	(46)
Depreciation	—	304	77	136	97	—	16	630
Retirement of assets	—	(158)	(23)	(3)	(6)	—	—	(190)
Disposals[3]	—	(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
Depreciation	**—**	**352**	**76**	**142**	**133**	**—**	**14**	**717**
Retirement of assets	**—**	**(31)**	**(10)**	**(6)**	**(4)**	**—**	**—**	**(51)**
Disposals	**—**	**(1)**	**—**	**—**	**—**	**—**	**(1)**	**(2)**
Change in foreign exchange rates	**—**	**(35)**	**18**	**(4)**	**(2)**	**—**	**2**	**(21)**
Transfers	**—**	**—**	**(212)**	**—**	**(29)**	**—**	**(14)**	**(255)**
As at Dec. 31, 2020	**—**	**4,281**	**772**	**1,416**	**938**	**—**	**169**	**7,576**
Carrying amount								
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
As at Dec. 31, 2020	**96**	**1,856**	**659**	**2,176**	**330**	**495**	**210**	**5,822**

(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) 2019 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.

(3) 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 Highvale 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).

(4) 2020 transfers out of PP&E mainly relate to removing the Southern Cross assets from PP&E to a finance lease receivable and moving the Pioneer Pipeline and mine equipment to assets held for sale. 2020 transfers between the classifications of PP&E relate to the Centralia land purchase, the Sundance Unit 6 conversion to gas, the WindCharger project and planned major maintenance. 2019 transfers mainly relate to transferring the Pioneer Pipeline and US Wind Projects from assets under construction to coal generation and renewable generation, respectively.

Additions in 2020 included cash additions related to the conversions to gas of $93 million, the Windrise wind project of $156 million, the WindCharger battery storage project of $6 million, the Kaybob cogeneration project of $31 million, Centralia mine land of $17 million and planned major maintenance expenditures. Additions in 2019 included 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.

Depreciation expense increased mainly as a result of decisions to accelerate the Highvale mine shutdown to align with our conversion to gas plans, reflecting our transition away from coal. Depreciation expense also increased due to the Keephills 3 and Genesee 3 swap, the reversal of the impairment at Centralia and the changes in useful lives, all of which were effective in the second half of 2019. For further details on these changes, refer to Note 3(A)(III) and Note 4(R).

In 2020, the Corporation capitalized $8 million (2019 — $6 million) of interest to PP&E in at a weighted average rate of 6.0 per cent (2019 —5.9 per cent).

19. 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)
Changes in foreign exchange rates	(1)	—	—	—	—	(1)
Transfers	—	—	—	(1)	—	(1)
As at Dec. 31, 2019	58	16	2	25	45	146
Additions	**3**	**13**	**—**	**—**	**—**	**16**
Depreciation	**(3)**	**(5)**	**(1)**	**(9)**	**(3)**	**(21)**
As at Dec. 31, 2020	**58**	**24**	**1**	**16**	**42**	**141**

(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 facilities as a result of revised interpretations of the unit of account identified asset concepts present in IFRS 16.

For the year ended Dec. 31, 2020, TransAlta paid $33 million (2019 — $25 million) related to recognized lease liabilities, consisting of $8 million in interest (2019 —$4 million) and $25 million (2019 — $21 million) in principal repayments.

For the year ended Dec. 31, 2020, the Corporation expensed nil related to short-term (2019 — $2 million) and nil related to low-value leases (2019 — $1 million). 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, 2020, the Corporation expensed $7 million (2019 — $6 million) in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 11, 24 and 36.

20. 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, 2018	185	339	237	46	807
Assets transferred to right-of-use assets on implementation of IFRS 16 (Note 19)	—	(5)	—	—	(5)
Additions	—	—	—	14	14
Acquisition	—	1	—	15	16
Disposals (Note 4(R))	(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
Additions	**—**	**—**	**—**	**14**	**14**
Acquisition (Note 4(K))	**—**	**—**	**37**	**—**	**37**
Disposals	**—**	**(1)**	**—**	**—**	**(1)**
Change in foreign exchange rates	**—**	**—**	**(2)**	**—**	**(2)**
Transfers	**—**	**35**	**(16)**	**(22)**	**(3)**
As at Dec. 31, 2020	**149**	**412**	**269**	**3**	**833**
Accumulated amortization					
As at Dec. 31, 2018	117	221	96	—	434
Assets transferred to right-of-use assets on implementation of IFRS 16 (Note 19)	—	(3)	—	—	(3)
Amortization	8	31	11	—	50
Disposals (Note 4(R))	(9)	(1)	—	—	(10)
Change in foreign exchange rates	—	(1)	—	—	(1)
Transfers	1	(1)	—	—	—
As at Dec. 31, 2019	117	246	107	—	470
Amortization	**8**	**28**	**15**	**—**	**51**
Disposals	**—**	**(1)**	**—**	**—**	**(1)**
Transfers	**—**	**(1)**	**1**	**—**	**—**
As at Dec. 31, 2020	**125**	**272**	**123**	**—**	**520**
Carrying amount					
As at Dec. 31, 2018	68	118	141	46	373
As at Dec. 31, 2019	32	132	143	11	318
As at Dec. 31, 2020	**24**	**140**	**146**	**3**	**313**

21. 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	2020	2019
Hydro	**258**	258
Wind and Solar	**175**	176
Energy Marketing	**30**	30
Total goodwill	**463**	464

For the purposes of the 2020 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment. In 2020, the Corporation relied on the recoverable amounts determined in 2019 for the Hydro and Energy Marketing segments in performing the 2020 annual goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumptions 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 2020 models ranged between $6 to $160 per MWh during the forecast period (2019 – $5 to $183 per MWh). Discount rates used for the goodwill impairment calculation in 2020 ranged from 4.8 per cent to 6.3 per cent (2019 – 3.6 per cent to 7.0 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

22. Other Assets

The components of other assets are as follows:

As at Dec. 31	2020	2019
South Hedland prepaid transmission access and distribution costs	**70**	67
Deferred licence fees	**—**	9
Project development costs	**25**	19
Long-term prepaids and other assets	**59**	56
Loan receivable	**52**	47
Total other assets	**206**	198

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 primarily include the project costs for US wind development projects (Note 4(F)) and an Alberta Hydro development project. Some projects were written off in 2019 and 2018 as they are no longer proceeding (see Note 7(D)).

Long-term prepaids and other assets includes: the funded portion of rail transportation commitments discussed in Note 36(C), the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 36(G) and other contractually required prepayments and deposits.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $52 million (2019 – $47 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.

23. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other	Total
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(1)	16	—	16
Reversals	—	(1)	(1)
Change in foreign exchange rates	(7)	—	(7)
Balance, Dec. 31, 2019	501	45	546
Liabilities incurred	**1**	**34**	**35**
Liabilities settled	**(18)**	**(19)**	**(37)**
Accretion	**30**	**—**	**30**
Acquisition of liabilities	**1**	**—**	**1**
Revisions in estimated cash flows(2)	**61**	**11**	**72**
Revisions in discount rates(3)	**36**	**—**	**36**
Reversals	**—**	**(6)**	**(6)**
Change in foreign exchange rates	**(4)**	**—**	**(4)**
Balance, Dec. 31, 2020	**608**	**65**	**673**

(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, the discount rates used for the Alberta Thermal and mining operations decommissioning provisions were changed. The use of a lower inflation rate decreased the corresponding liabilities.

(2) During 2020, the Corporation adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity including increased volume of material movement. Refer to Note 3(A)(III) for further details. This increase was partially offset by a decrease in the Sarnia decommissioning and restoration provision as a result of an updated engineering study.

(3) Discount rates at Dec. 31, 2020 are generally lower than those at Dec. 31, 2019, due to decreases in the underlying risk-free US and Canadian benchmark yields and changes in credit spreads due to volatility within the market as a result of COVID-19. On average, these rates decreased by approximately 0.3 to 0.9 per cent.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2019	501	45	546
Current portion	36	22	58
Non-current portion	465	23	488
Balance, Dec. 31, 2020	**608**	**65**	**673**
Current portion	**21**	**38**	**59**
Non-current portion	**587**	**27**	**614**

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 $1.4 billion, which will be incurred between 2021 and 2073. The majority of the costs will be incurred between 2025 and 2050. At Dec. 31, 2020, the Corporation had provided a surety bond in the amount of US$147 million (2019 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2020, the Corporation had provided letters of credit in the amount of $131 million (2019 – $128 million) in support of future decommissioning obligations at the Alberta Highvale 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.

In addition, during the fourth quarter of 2020 an onerous contract provision of $29 million was recognized as a result of a decision to accelerate our plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. The last coal shipment is expected to be received during the first quarter of 2021, while payments required under the contract will continue until 2025.

24. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	2020			2019		
	Carrying value	**Face value**	**Interest[1]**	Carrying value	Face value	Interest[1]
Credit facilities[2]	**114**	**114**	**2.7%**	220	220	3.5%
Debentures	**249**	**251**	**7.1%**	647	651	5.8%
Senior notes[3]	**886**	**894**	**5.4%**	905	914	5.4%
Non-recourse[4]	**1,837**	**1,858**	**4.1%**	1,144	1,157	4.3%
Other[5]	**141**	**147**	**7.1%**	154	162	7.1%
	3,227	**3,264**		3,070	3,104	
Lease liabilities	**134**			142		
	3,361			3,212		
Less: current portion of long-term debt	**(97)**			(494)		
Less: current portion of lease liabilities	**(8)**			(19)		
Total current long-term debt and lease liabilities	**(105)**			(513)		
Total credit facilities, long-term debt and lease liabilities	**3,256**			2,699		

(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, 2020 — US$700 million (Dec. 31, 2019 — US$700 million).
(4) Includes AU$800 million TEC offering.
(5) Includes US$110 million at Dec. 31, 2020 (Dec. 31, 2019 — US$117 million) of tax equity financing.

The Corporation's credit facilities are summarized in the table below:

		Utilized			
As at Dec. 31, 2020	**Facility size**	**Outstanding letters of credit[1]**	**Actual drawings**	**Available capacity**	**Maturity date**
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	379	114	757	Q2 2023
Canadian committed bilateral credit facilities[3]	240	150	—	90	Q2 2021 & 2022
TransAlta Renewables					
Committed credit facility[2]	700	92	—	608	Q2 2023
Total	**2,190**	**621**	**114**	**1,455**	

(1) TransAlta has 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, 2020, we provided cash collateral of $49 million.
(2) TransAlta has letters of credit of $89 million and TransAlta Renewables has letters of credit of $92 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.
(3) One of the bilateral $80 million credit facilities has a maturity date of Q2 2021;the remaining two bilateral credit facilities has a maturity date of Q2, 2022.

The $1.95 billion (Dec. 31, 2019 – $1.95 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.

In 2019, the Corporation renewed these credit facilities and TransAlta Renewables' facility was increased by $200 million to $700 million.

The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.5 billion available under the credit facilities, the Corporation also has $703 million of available cash and cash equivalents and $17 million ($11 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

<u>Debentures</u> bear interest at fixed rates ranging from 6.9 per cent to 7.3 per cent and have maturity dates ranging from 2029 to 2030.

On Nov. 25, 2020, the Corporation redeemed $400 million of its then due 5.0 per cent medium term notes.

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.

<u>Senior notes</u> 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.

A total of US$370 million (2019 — US$370 million) of the senior notes has been designated as a hedge of the Corporation’s net investment in US foreign operations.

<u>Non-recourse debt</u> consists of bonds and debentures that have maturity dates ranging from 2023 to 2042 and bear interest at rates ranging from 2.95 per cent to 4.51 per cent.

On Oct. 22, 2020, TEC closed an AU$800 million senior secured note offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The notes bear interest at 4.07 per cent per annum, payable quarterly and matures on June 30, 2042,with principal payments starting on March 31, 2022. Funds were used repay indebtedness on the credit facility and to fund future growth opportunities within TransAlta Renewables.

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.

<u>Other</u> 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 $112 million (2019 – $122 million) and Lakeswind of $22 million (2019 – $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(T) 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 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, 2029.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2020, 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, TEC Hedland and TransAlta OCP non-recourse bonds with a carrying value of $1.8 billion as at Dec. 31, 2020 (Dec. 31, 2019 - $1.1 billion) 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 third quarter of 2020. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2021. At Dec. 31, 2020, $73 million (Dec. 31, 2019 –$42 million) of cash was subject to these financial restrictions.

Proceeds received from the TEC Notes in the amount of AU$7 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 major maintenance costs.

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.

C. Security

Non-recourse debts totalling $1,441 million as at Dec. 31, 2020 (Dec. 31, 2019 – $719 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 PPE with total carrying amounts of $1,277 million at Dec. 31, 2020 (Dec. 31, 2019 – $967 million) and intangible assets with total carrying amounts of $88 million (Dec. 31, 2019 – $63 million). At Dec. 31, 2020, a non-recourse bond of approximately $111 million (Dec. 31, 2019 – $119 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 $285 million (Dec. 31, 2019 – $305 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

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Principal repayments(1)	96	626	277	119	136	2,010	3,264
Lease liabilities(2)	(5)	6	5	5	5	118	134

(1) Excludes impact of hedge accounting and derivatives.
(2) Lease liabilities include a lease incentive of $13 million, expected to be received in 2021.

E. Restricted Cash

At Dec. 31, 2020, the Corporation had $9 million (Dec. 31, 2019 – $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 2021.

The Corporation had $17 million (Dec. 31, 2019 – $17 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 2021.

The Corporation also had $45 million (Dec. 31, 2019 – nil) of restricted cash related to the TEC Notes; reserves are required to be held under TEC commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

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, 2020, was $621 million (2019 – $690 million) with no (2019 – nil) amounts exercised by third parties under these arrangements.

25. Exchangeable Securities

On March 22, 2019, the Corporation 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. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in exchange for redeemable, retractable first preferred shares.

A. $750 million Exchangeable Securities

As at	Dec. 31, 2020			Dec. 31, 2019		
	Carrying value	**Face value**	**Interest**	**Carrying value**	**Face value**	**Interest**
Exchangeable debentures – due May 1, 2039	**330**	**350**	**7 %**	326	350	7 %
Exchangeable preferred shares[1]	**400**	**400**	**7 %**	—	—	7 %
Total long term debt	**730**	**750**		**326**	**350**	

(1) Exchangeable preferred share dividends are reported as interest expense.

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, 2020		Dec. 31, 2019	
Description	**Base fair value**	**Sensitivity**	**Base fair value**	**Sensitivity**
Option to exchange – embedded derivative	**—**	**nil** **-33**	—	nil -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.

26. 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	2020	2019
Defined benefit obligation (Note 31)	**282**	268
Long-term incentive accruals (Note 30)	**4**	4
Other	**12**	29
Total	**298**	301

27. 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	2020		2019	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**277.0**	**2,978**	284.6	3,059
Purchased and cancelled under the NCIB	**(7.3)**	**(79)**	(7.7)	(83)
Effects of share-based payment plans	**—**	**(3)**	—	—
Stock options exercised	**0.1**	**—**	0.1	2
Issued and outstanding, end of year	**269.8**	**2,896**	277.0	2,978

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	2020	2019
Total shares purchased[1]	**7,352,600**	7,716,300
Average purchase price per share	**$ 8.33**	$ 8.80
Total cost	**61**	68
Weighted average book value of shares cancelled	**79**	83
Amount recorded in deficit	**18**	15

(1) As at Dec. 31, 2020, includes 456,200 (2019 -189,900) 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	2020	2019	2018
Net earnings (loss) attributable to common shareholders	**(336)**	52	(248)
Basic and diluted weighted average number of common shares outstanding (millions)	**275**	283	287
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(1.22)**	0.18	(0.86)

E. Dividends

On Dec. 23, 2020, the Corporation declared a quarterly dividend of $0.0450 per common share, payable on April 1, 2021. On Nov. 3, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Jan. 1, 2021.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

28. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

As at Dec. 31	2020		2019	
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, 2020.

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.

On March 1, 2021, the Corporation announced that it does not intend to exercise its right to redeem all or any part of the currently outstanding Series A Shares and Series B Shares. The Corporation has provided a notice to the registered shareholders of Series A Shares of the conversion right, on a one-for-one basis, into Series B Shares, and vice versa, providing Series B shareholders the right to exchange Series B Shares, on a one-for-one basis, into Series A Shares. Series A shareholders may elect to retain any or all of their current share holdings and continue to receive a fixed rate quarterly dividend. Series B shareholder may also elect to retain any or all of their current share holdings and continue to receive a floating rate quarterly dividend. After exercising conversion rights, if the balance that remains for either

Series A Shares or Series B Shares is less than 1 million, that remaining balance of will automatically convert to the other Series. Shareholders' notice of intention to convert must be received by the transfer agent no later than March 16, 2021 and the conversion date will be effective March 31, 2021. The annual dividend rate for the Series A Shares for the five-year period from and including March 31, 2021, to, but excluding, March 31, 2026, will be 2.877 per cent, which is equal to the five-year Government of Canada Bond yield of 0.847 per cent, determined as of March 1, 2021, plus 2.03 per cent. The annual dividend rate for the Series B Shares for the three month floating rate period from and including March 31, 2021, to, but excluding, June 30, 2021, will be 2.103 per cent based on the most recent auction of 90-day Government of Canada Treasury Bills of 0.073 per cent plus 2.03 per cent. The Floating Quarterly Dividend Rate will be reset every quarter.

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, 2020, 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	0.67724	March 31, 2021	2.03	B
B	Floating	0.73801	March 31, 2021	2.03	A
C	Fixed	1.00676	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29852	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.24700	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of the preferred share dividends declared in 2020, 2019 and 2018:

	Total dividends declared		
Series	**2020**	2019(1)	2018
A	**9**	5	9
B(2)	**1**	1	1
C	**14**	8	14
E	**15**	9	15
G	**10**	7	11
Total for the year	**49**	30	50

(1) No dividends were declared in the first quarter of 2019 as the quarterly dividend related to the period covering the first quarter of 2019 was declared in December 2018.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

On Dec. 23, 2020, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.13186 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, all payable on March 31, 2021.

29. Accumulated Other Comprehensive Income

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

	2020	2019
Currency translation adjustment		
Opening balance, Jan. 1	**(21)**	17
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(11)**	(59)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**11**	21
Balance, Dec. 31	**(21)**	(21)
Cash flow hedges		
Opening balance, Jan. 1	**527**	508
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(1)	**(91)**	19
Balance, Dec. 31	**436**	527
Employee future benefits		
Opening balance, Jan. 1	**(55)**	(29)
Net actuarial gains (losses) on defined benefit plans, net of tax(2)	**(11)**	(26)
Balance, Dec. 31	**(66)**	(55)
Other		
Opening balance, Jan. 1	**3**	(15)
Change in ownership of TransAlta Renewables	**—**	1
Intercompany investments at FVOCI	**(50)**	17
Balance, Dec. 31	**(47)**	3
Accumulated other comprehensive income	**302**	454

(1) Net of income tax of $23 million for the year ended Dec. 31, 2020 (2019 — $6 million).
(2) Net of income tax of $3 million for the year ended Dec. 31, 2020 (2019 — $7 million).

30. 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 2020 was $15 million (2019 – $19 million, 2018 – $8 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 $1 million in 2020 (2019 – $2 million, 2018 – nil).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 16.5 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 2020, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with a weighted average exercise price of $9.17 that vest after a three-year period and expire seven years after issuance (2019 – 1.4 million stock options at $5.65; 2018 – 0.7 million stock options at $7.45). The expense recognized relating to these grants during 2020 was approximately $2 million (2019 – approximately $1 million, 2018 – approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2020, 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 - 10.00	**4.0**	**4.2**	**6.85**

(1) Options currently exercisable as at Dec. 31, 2020.

31. 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, 2020. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2019. 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, 2020.

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 2020 for the amount of $89 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, 2019, and Jan. 1, 2020, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2020.

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, 2020	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**5**	**2**	**1**	**8**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**16**	**3**	**1**	**20**
Interest on plan assets	**(11)**	**(1)**	**—**	**(12)**
Curtailment and amendment gain	**(2)**	**—**	**—**	**(2)**
Defined benefit expense	**9**	**4**	**2**	**15**
Defined contribution expense	**9**	**—**	**—**	**9**
Net expense	**18**	**4**	**2**	**24**

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

C. Status of Plans

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

Year ended Dec. 31, 2020	Registered	Supplemental	Other	Total
Fair value of plan assets	**367**	**14**	**–**	**381**
Present value of defined benefit obligation	**(542)**	**(109)**	**(24)**	**(675)**
Funded status – plan deficit	**(175)**	**(95)**	**(24)**	**(294)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(5)**	**(5)**	**(2)**	**(12)**
Other long-term liabilities	**(170)**	**(90)**	**(22)**	**(282)**
Total amount recognized	**(175)**	**(95)**	**(24)**	**(294)**

Year ended 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)

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, 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
Interest on plan assets	**11**	**1**	**–**	**12**
Net return on plan assets	**25**	**(1)**	**–**	**24**
Contributions	**6**	**6**	**1**	**13**
Benefits paid	**(45)**	**(5)**	**(1)**	**(51)**
Administration expenses	**(1)**	**–**	**–**	**(1)**
Effect of translation on US plans	**(2)**	**–**	**–**	**(2)**
As at Dec. 31, 2020	**367**	**14**	**–**	**381**

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

Year ended Dec. 31, 2020	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**–**	**64**	**–**	**64**
US	**–**	**30**	**–**	**30**
International	**–**	**103**	**–**	**103**
Private	**–**	**–**	**1**	**1**
Bonds				
AAA	**–**	**36**	**–**	**36**
AA	**–**	**67**	**–**	**67**
A	**–**	**34**	**–**	**34**
BBB	**1**	**22**	**–**	**23**
Below BBB	**–**	**4**	**–**	**4**
Money market and cash and cash equivalents	**–**	**19**	**–**	**19**
Total	**1**	**379**	**1**	**381**

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

Plan assets do not include any common shares of the Corporation at Dec. 31, 2020 and Dec. 31, 2019. The Corporation charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2020 (2019 – nil).

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, 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 gain arising from demographic assumptions	—	—	(2)	(2)
Actuarial 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
Current service cost	**5**	**2**	**1**	**8**
Interest cost	**16**	**3**	**1**	**20**
Benefits paid	**(45)**	**(5)**	**(1)**	**(51)**
Curtailment	**(2)**	**—**	**—**	**(2)**
Actuarial loss arising from demographic assumptions	**—**	**—**	**—**	**—**
Actuarial loss arising from financial assumptions	**43**	**10**	**2**	**55**
Actuarial gain arising from experience adjustments	**(17)**	**—**	**—**	**(17)**
Effect of translation on US plans	**(1)**	**—**	**(1)**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2020	**542**	**109**	**24**	**675**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2020 is 14.4 years.

F. Contributions

The expected employer contributions for 2021 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**5**	**2**	**12**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2020			As at Dec. 31, 2019		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**2.4**	**2.3**	**2.3**	3.0	3.0	3.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.8	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**6.8**	—	—	7.0
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.0**	**3.0**	**3.0**	3.9	3.8	3.9
Rate of compensation increase	**2.9**	**3.0**	**—**	2.5	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.1**	—	—	7.4
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0

(1) 2020 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 0.3% per year to 4.5% in 2030 for Canada.
(2) 2020 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 0.3% per year to 4.5% in 2030 for Canada.
(3) 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.
(4) 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 0.3% 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, 2020	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**74**	**17**	**2**	**3**	**1**
1% increase in the salary scale	**5**	**—**	**—**	**4**	**1**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**4**	**—**	**1**	**—**

32. Joint Arrangements

Joint arrangements at Dec. 31, 2020, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Alberta Thermal	50	Dual-fuel facility 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	Alberta Thermal	50	Natural gas pipeline in Alberta operated by TMI
Goldfields Power	Australian Gas	50	Gas-fired facility in Australia operated by TransAlta
Fort Saskatchewan	North American Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Australian Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

Joint ventures	Segment	Ownership *(per cent)*	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2020**	2019	2018
(Use) source:			
Accounts receivable	**(79)**	261	58
Prepaid expenses	**2**	—	19
Income taxes receivable	**(4)**	(6)	—
Inventory	**6**	(13)	(21)
Accounts payable, accrued liabilities and provisions	**160**	(130)	(97)
Income taxes payable	**4**	9	(3)
Change in non-cash operating working capital	**89**	121	(44)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2019	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2020
Long-term debt and lease obligations	3,212	**133**	**16**	**—**	**5**	**(5)**	**3,361**
Exchangeable securities	326	**400**	**—**	**—**	**—**	**4**	**730**
Dividends payable (common and preferred)	37	**(86)**	**—**	**107**	**—**	**1**	**59**
Total liabilities from financing activities	3,575	**447**	**16**	**107**	**5**	**—**	**4,150**

	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 liabilities	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**

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2020	2019	Increase/ (decrease)
Long-term debt[1]	**3,361**	3,212	**149**
Exchangeable securities	**730**	326	**404**
Equity			
Common shares	**2,896**	2,978	**(82)**
Preferred shares	**942**	942	**—**
Contributed surplus	**38**	42	**(4)**
Deficit	**(1,826)**	(1,455)	**(371)**
Accumulated other comprehensive income	**302**	454	**(152)**
Non-controlling interests	**1,084**	1,101	**(17)**
Less: available cash and cash equivalents[2]	**(703)**	(411)	**(292)**
Less: principal portion of restricted cash on TransAlta OCP bonds[3]	**(11)**	(10)	**(1)**
Less: fair value asset of hedging instruments on long-term debt[4]	**(2)**	(7)	**5**
Total capital	**6,811**	7,172	**(361)**

(1) Includes lease liabilities, 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). During 2020, Moody's reaffirmed its issuer rating of Ba1 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 reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of 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	**2020**	2019	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.2**	4.5	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**18.3**	19.0	20 to 25
Adjusted net debt to adjusted comparable earnings before interest, taxes, depreciation and amortization (times)	**3.9**	3.9	3.0 to 3.5
Deconsolidated net debt to deconsolidated comparable EBITDA (times)	**4.6**	4.2	2.5 to 3.0

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 liabilities (net of capitalized interest) divided by interest on debt, exchangeable securities and lease liabilities (net of capitalized interest) plus 50 per cent of dividends paid on preferred shares. The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. 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 exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Adjusted Comparable 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 exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

Deconsolidated net debt to deconsolidated comparable EBITDA is calculated as deconsolidated net debt (long-term debt, lease liabilities and exchangeable debentures including current portion and fair value (asset) liability of hedging instruments on debt plus 50 per cent issued preferred shares less cash and cash equivalents less principal portion of TransAlta OCP restricted cash less TransAlta Renewables long-term debt and lease liabilities including current portion less tax equity financing) divided by deconsolidated comparable EBITDA (comparable EBITDA less TransAlta Renewables comparable EBITDA less TA Cogen comparable EBITDA plus dividends received from TransAlta Renewables plus dividends received from TA Cogen). The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 2.5 to 3.0 times.

At times, the credit ratios may be outside of the specified ranges while the Corporation executes its conversion to gas 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, 2020 and 2019, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2020	2019	Increase (decrease)
Cash flow from operating activities	**702**	849	**(147)**
Change in non-cash working capital	**(89)**	(121)	**32**
Cash flow from operations before changes in working capital	**613**	728	**(115)**
Dividends paid on common shares	**(47)**	(45)	**(2)**
Dividends paid on preferred shares	**(39)**	(40)	**1**
Distributions paid to subsidiaries' non-controlling interests	**(97)**	(106)	**9**
Property, plant and equipment expenditures	**(486)**	(417)	**(69)**
Inflow (outflow)	**(56)**	120	**(176)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2020, $1.5 billion (2019 – $1.3 billion) of the Corporation's credit facilities were fully available.

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.

35. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2020, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	60.1	Generation and sale of electricity

Associate or joint venture	Country	Ownership (per cent)	Principal activity
SP Skookumchuck Investment, LLC	US	49	Generation and sale of electricity
EMG International, LLC	US	30	Wastewater treatment and biogas fuel to generate electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed. Associates and joint ventures have been equity accounted for by the Corporation.

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	2020	2019	2018
Total compensation	**27**	30	17
Comprised of:			
Short-term employee benefits	**12**	13	11
Post-employment benefits	**2**	2	2
Termination benefits	**–**	2	–
Share-based payments	**13**	13	4

36. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Natural gas, transportation and other contracts	141	149	137	134	134	1,353	**2,048**
Transmission	8	8	8	5	5	1	**35**
Coal supply and mining agreements	81	105	101	67	56	—	**410**
Long-term service agreements	31	37	22	18	10	55	**173**
Operating leases	4	2	2	1	1	26	**36**
Growth	509	411	93	—	—	—	**1,013**
TransAlta Energy Transition Bill	6	6	6	—	—	—	**18**
Total	**780**	**718**	**369**	**225**	**206**	**1,435**	**3,733**

A. Natural Gas, Transportation and Other Contracts

The Corporation has fixed price or volume natural gas purchase and transportation contracts. In addition to the commitments shown above, upon closing the sale of the Pioneer Pipeline, a 15-year transportation agreement will provide an additional 275 TJ per day of natural gas on a firm basis by 2023, bringing the total firm natural gas transportation contracts to 400 TJ per day by 2023. This agreement would replace the Corporation's existing 15-year commitment to purchase 139 TJ per day of natural gas on the Pioneer Pipeline, which remains in place until the closing of the Transaction. 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 thermal facility. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2025. In 2020, a new rail transportation service contract was entered into and pricing is reflective of current market conditions. As a result, there is an increase in expected rail transportation costs over the service period.

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 accelerated plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021.

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, operating lease expenses were recognized as incurred in the statement of earnings. During the year ended Dec. 31, 2018, $8 million was recognized as an expense in respect of operating leases. Sublease payments received during 2020 were $2 million (2019 and 2018 – 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: conversion to gas and repowering Sundance Unit 5, Kaybob cogeneration project, Windrise project and any final costs associated with the Big Level and Antrim wind 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 MOA, 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, 2020, the Corporation has funded approximately US$41 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 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. The AESO submitted a review and variance application of this decision to implement a "pay-as-you-go" invoicing scheme rather than issue a single invoice. The AUC ruled on the AESO's request and approved a three-period invoice process (2006-2009, 2010-2013 and 2014-2016). The total liability for the loss charges was $25 million; however, due to payments made (and received) for the first two invoices, only $8 million of the total liability remains outstanding. The AESO issued the first invoice on Oct. 22, 2020 for $6 million, which was paid by Dec. 30, 2020. The second invoice was issued on Dec. 21, 2020, for $11 million. The third invoice is expected in March 2021.

In November 2020, the AESO sought direction from the AUC with respect to interest payments on the loss charges and the AUC ruled in January 2021 that simple interest rather than compound interest would apply to the loss charges.

II. FMG Disputes

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments 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 has been rescheduled to proceed to trial beginning May 3, 2021, instead of June 15, 2020.

The Corporation had a second dispute involving FMG's claims against TransAlta related to the transfer of the Solomon facility to FMG. FMG claimed certain amounts related to the condition of the facility while TransAlta claimed certain outstanding costs that should be reimbursed. The dispute was settled and discontinued in the Supreme Court of Western Australia on Sept. 9, 2020.

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 of Directors of the Corporation on such date and Brookfield BRP Holdings (Canada), as defendants. Mangrove is seeking to set aside the Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter has been rescheduled and the three-week trial will begin on April 19, 2021.

IV. Keephills 1 Stator Force Majeure
The Balancing Pool and ENMAX Energy Corporation ("ENMAX") are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal is scheduled to be heard on April 8, 2021. TransAlta believes that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was fair.

V. Keephills 1 Superheater Force Majeure
Keephills Unit 1 was taken offline from March 17, 2015 to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta Generation Partnership claimed force majeure under the Keephills PPA. ENMAX, the PPA buyer under the PPA at the time, did not dispute the force majeure, but the Balancing Pool did, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The Balancing Pool argued and won in the Courts that it has a right under the PPA to commence an arbitration, independent of the PPA buyer, ENMAX. An arbitration for this dispute has commenced and is set to be heard for seven days starting Dec. 6, 2021.

VI. 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 Highvale mine. The Balancing Pool and Utilities Consumer Advocate are participating as interveners because they take issue with the decommissioning costs claimed by TransAlta. Due to various factors including the COVID-19 pandemic and significant information requests from the Balancing Pool, the application has been delayed. While a hearing date has not been set, the application will likely be heard in late 2021 or early 2022. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

VII. Hydro Power Purchase Arrangement ("Hydro PPA") Emission Performance Credits
The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $17 million per year, earned by the Hydro facilities under the *Carbon Competitiveness Incentive Regulation* from 2018-2020. 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. An arbitration has commenced and will be likely set down for a hearing sometime in early 2022.

VIII. Direct Assigned Capital Deferral Account ("DACDA") Application
AltaLink Management Ltd. ("AltaLink") filed an application before the AUC to recover its 2016-2018 DACDA costs (the "Proceeding") incurred for the 240 kV line upgrades project in the Edmonton region (the "Upgrades Project"). TransAlta is a secondary applicant in the Proceeding because it owns a portion of the 1043L Line located on Enoch Cree Nation ("ECN") Reserve that was a part of the Upgrades Project. AltaLink and TransAlta sought to have their costs ($91 million for AltaLink and $22 million for TransAlta) approved by the AUC as reasonable and prudent. The ECN and the Consumers' Coalition of Alberta are registered participants in the Proceeding. The AUC rendered its decision in the Proceeding on Dec. 10, 2020, and disallowed 15 per cent (approximately $3 million) of TransAlta's portion. TransAlta believes that the AUC made errors by disallowing 15 per cent of its costs and therefore filed a permission to appeal application with the Court of Appeal (the "PTA") and a review and variance application with the AUC (the "R&V"). The PTA will be adjourned until the R&V process is completed.

37. Segment Disclosures

A. Description of Reportable Segments

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

The following tables provides each segment's results in the format that management organizes its segments to make operating decisions and assess performance. For internal reporting purpose, the earnings information from the Corporation's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Corporation's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not, and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method. The table below also shows the reconciliation of the total segmented results to the statement of earnings reported under IFRS.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2020	Hydro	Wind and Solar[1]	North American Gas[2]	Australian Gas	Alberta Thermal[3]	Centralia[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	IFRS Financials
Revenues	152	332	217	158	619	497	122	7	2,104	(3)	2,101
Fuel, carbon compliance and purchased power	8	25	66	10	573	279	—	7	968	—	968
Gross margin	144	307	151	148	46	218	122	—	1,136	(3)	1,133
Operations, maintenance and administration	37	53	49	32	131	60	30	80	472	—	472
Depreciation and amortization	28	136	46	43	270	105	2	25	655	(1)	654
Asset impairment	2	—	—	—	75	7	—	—	84	—	84
Taxes, other than income taxes	2	8	2	—	15	5	—	1	33	—	33
Net other operating expense (income)	—	—	—	—	(11)	—	—	—	(11)	—	(11)
Operating income (loss)	75	110	54	73	(434)	41	90	(106)	(97)	(2)	(99)
Equity income from associate[1]	—	—	—	—	—	—	—	—	—	1	1
Finance lease income	—	—	5	2	—	—	—	—	7	—	7
Net interest expense									(239)	1	(238)
Foreign exchange loss									17	—	17
Gain on sale of assets and other									9	—	9
Earnings before income taxes									(303)	—	(303)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(3) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

Year ended Dec. 31, 2019	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate	Total
Revenues	156	312	209	160	816	571	129	(6)	2,347
Fuel, carbon compliance and purchased power	7	16	74	9	570	416	—	(6)	1,086
Gross margin	149	296	135	151	246	155	129	—	1,261
Operations, maintenance and administration	36	50	44	37	138	67	30	73	475
Depreciation and amortization	32	124	41	48	233	83	2	27	590
Asset impairment (reversal)	2	—	—	—	15	(10)	—	18	25
Gain on termination of Keephills 3 coal rights contract (Note 4(R))	—	—	—	—	(88)	—	—	—	(88)
Taxes, other than income taxes	3	8	1	—	13	3	—	1	29
Termination of Sundance B and C PPAs (Note 9)	—	—	—	—	(56)	—	—	—	(56)
Net other operating expense (income)	—	(10)	(1)	—	(40)	—	—	2	(49)
Operating income (loss)	76	124	50	66	31	12	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

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

Year ended Dec. 31, 2018	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate	Total
Revenues	156	282	232	165	912	442	67	(7)	2,249
Fuel, carbon compliance and purchased power	6	17	96	8	666	314	—	(7)	1,100
Gross margin	150	265	136	157	246	128	67	—	1,149
Operations, maintenance and administration	38	50	48	37	171	61	24	86	515
Depreciation and amortization	30	110	43	49	241	74	2	25	574
Asset impairment	—	12	—	—	38	—	—	23	73
Taxes, other than income taxes	3	8	1	—	13	5	—	1	31
Termination of Sundance B and C PPAs (Note 9)	—	—	—	—	(157)	—	—	—	(157)
Net other operating income	—	(6)	—	—	(41)	—	—	—	(47)
Operating income (loss)	79	91	44	71	(19)	(12)	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)

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2020	Hydro	Wind and Solar	North American Gas(2)	Australian Gas	Alberta Thermal(1)	Centralia(1)	Energy Marketing	Corporate	Total
PP&E	467	2,005	382	421	2,271	260	—	16	5,822
Right-of-use assets	6	55	1	4	53	—	—	22	141
Intangible assets	4	159	32	34	31	5	7	41	313
Goodwill	258	175	—	—	—	—	30	—	463

As at Dec. 31, 2019	Hydro	Wind and Solar	North American Gas(2)	Australian Gas	Alberta Thermal(1)	Centralia(1)	Energy Marketing	Corporate	Total
PP&E	469	1,947	392	489	2,540	352	1	17	6,207
Right-of-use assets	6	56	—	4	68	—	—	12	146
Intangible assets	5	173	2	37	41	6	9	45	318
Goodwill	258	176	—	—	—	—	30	—	464

(1) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2020	Hydro	Wind and Solar	North American Gas(2)	Australian Gas	Alberta Thermal(1)	Centralia(1)	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	22	174	39	10	200	28	—	13	486
Intangible assets	—	—	—	—	1	—	—	13	14

Year ended Dec. 31, 2019	Hydro	Wind and Solar	North American Gas(2)	Australian Gas	Alberta Thermal(1)	Centralia(1)	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	23	229	36	6	114	8	—	1	417
Intangible assets	—	—	—	—	2	—	—	12	14

Year ended Dec. 31, 2018	Hydro	Wind and Solar	North American Gas(2)	Australian Gas	Alberta Thermal(1)	Centralia(1)	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	16	117	21	6	101	14	—	2	277
Intangible assets	—	—	—	—	3	—	—	17	20

(1) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.

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	2020	2019	2018
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**654**	590	574
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**144**	119	136
Depreciation and amortization on the Consolidated Statements of Cash Flows	**798**	709	710

C. Geographic Information

I. Revenues

Year ended Dec. 31	2020	2019	2018
Canada	**1,227**	1,460	1,573
US	**716**	727	511
Australia	**158**	160	165
Total revenue	**2,101**	2,347	2,249

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Canada	**4,661**	4,854	**107**	109	**185**	213	**74**	75	**418**	418
US	**737**	863	**30**	33	**94**	68	**61**	47	**45**	46
Australia	**424**	490	**4**	4	**34**	37	**71**	76	**—**	—
Total	**5,822**	6,207	**141**	146	**313**	318	**206**	198	**463**	464

D. Significant Customer

During the year ended Dec. 31, 2020, no sales to any one customer was greater than 10 per cent of the Corporation's total revenue (2019 – one customer within the Alberta Thermal and Hydro segments represented 11 per cent of total revenue).

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, 2020:

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

(0.46) 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	2020	2019	2018
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,101**	2,347	2,249
Operating income	**(99)**	335	160
Net earnings (loss) attributable to common shareholders	**(336)**	52	(248)
STATEMENT OF FINANCIAL POSITION			
Total assets	**9,747**	9,508	9,428
Current portion of long-term debt, net of cash and cash equivalents	**(598)**	102	59
Credit facilities, long-term debt and finance lease obligations	**3,256**	2,699	3,119
Non-controlling interests	**1,084**	1,101	1,137
Preferred shares	**942**	942	942
Equity attributable to common shareholders(1)	**1,410**	2,019	2,055
Fair value (asset) liability of hedging instruments on debt(1)	**(2)**	(7)	(10)
Total capital(2)	**6,811**	7,172	7,275
CASH FLOWS			
Cash flow from operating activities	**702**	849	820
Cash flow from (used in) investing activities	**(687)**	(512)	(394)
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**(1.22)**	0.18	(0.86)
Comparable earnings(1)	**n/a**	n/a	n/a
Dividends declared on common share	**0.22**	0.12	0.20
Book value per common share (at year-end)(1)	**5.13**	7.14	7.16
Market price:			
High	**11.23**	10.14	7.90
Low	**5.32**	5.50	5.44
Close (Toronto Stock Exchange at Dec. 31)	**9.67**	9.28	5.59
RATIOS (percentage except where noted)			
Adjusted net debt to total capital(1)	**53.5**	49.9	49.7
Adjusted net debt to total capital excluding non-recourse debt(1)	**36.7**	40.7	39.4
Adjusted net debt to adjusted comparable EBITDA(1,3,4) (times)	**3.9**	3.9	3.6
Return on equity attributable to common shareholders(1)	**(30.3)**	3.3	(15.8)
Comparable return on equity attributable to common shareholders(1)	**n/a**	n/a	n/a
Return on capital employed(1)	**(1.7)**	4.3	0.7
Comparable return on capital employed(1)	**n/a**	n/a	n/a
Earnings coverage (times)(1)	**(0.5)**	1.5	0.2
Dividend payout ratio based on FFO(1,4)	**7.0**	6.6	6.1
Comparable EBITDA(1,3,4) (in millions of Canadian dollars)	**927**	984	1,123
Dividend coverage(1,4) (times)	**15.6**	18.6	18.3
Dividend yield(1)	**1.7**	1.7	2.9
Adjusted FFO to adjusted net debt(1,4)	**18.3**	19.0	20.8
FFO before interest to adjusted interest coverage(1,4) (times)	**4.2**	4.5	4.8
Weighted average common shares for the year (in millions)	**275**	283	287
Common shares outstanding at Dec. 31 (in millions)	**270**	277	285
STATISTICAL SUMMARY			
Number of employees	**1,476**	1,543	1,883
Gross installed capacity (MW)(5)			
Alberta Thermal and Centralia	**4,206**	4,569	4,571
Gas (Canadian and Australian)(6)	**1,424**	1,395	1,395
Renewables (wind, solar and hydro)	**2,498**	2,421	2,308
Equity investments	**137**	—	—
Total generating capacity	**8,265**	8,385	8,273
Total generation production (GWh)	**24,980**	29,071	28,409

Financial data presented is based on IFRS. 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. After 2016, comparable earnings measures are no longer being calculated or reported on.

(2) Total capital for 2014 to 2010 has been revised to align with the 2015 calculation methodology.

2017	2016	2015	2014	2013	2012	2011	2010
2,307	2,397	2,267	2,623	2,292	2,210	2,618	2,673
138	478	148	442	195	(214)	645	487
(190)	117	(24)	141	(71)	(615)	290	255
10,304	10,996	10,947	9,833	9,624	9,503	9,780	9,635
433	334	33	708	175	582	284	202
2,960	3,722	4,408	3,305	4,130	3,610	3,721	3,823
1,059	1,152	1,029	594	517	330	358	431
942	942	942	942	781	—	—	—
2,384	2,569	2,419	2,342	2,125	3,018	3,274	3,120
(30)	(163)	(190)	(96)	(16)	50	32	41
7,748	8,556	8,641	7,795	7,712	7,590	7,669	7,617
626	744	432	796	765	520	690	838
87	(327)	(573)	(292)	(703)	(1,048)	(608)	(765)
(0.66)	0.41	(0.09)	0.52	(0.27)	(2.62)	1.31	1.16
n/a	0.13	(0.17)	0.25	0.31	0.50	1.05	0.97
0.16	0.30	0.72	0.83	1.16	1.16	1.16	1.16
8.28	8.92	8.52	8.52	7.92	8.78	12.08	12.85
8.50	7.54	12.34	14.94	16.86	21.37	23.24	23.98
6.88	3.76	4.13	9.81	12.91	14.11	19.45	19.61
7.45	7.43	4.91	10.52	13.48	15.12	21.02	21.15
49.5	51.0	54.6	56.3	60.7	61.0	52.5	53.1
41.8	44.2	50.2	54.1	58.7	59.0	60.0	50.7
3.6	3.8	5.4	4.2	4.6	4.6	3.8	—
(10.0)	5.4	(1.2)	6.3	(3.2)	(25.9)	10.6	9.6
n/a	1.7	(2.3)	3.0	3.7	4.9	8.4	8.0
2.1	5.3	4.6	5.8	2.8	(3.1)	8.3	6.6
n/a	4.4	3.0	5.1	5.2	5.3	7.0	6.0
0.6	1.7	1.5	1.7	0.8	(1.0)	2.7	2.2
4.3	8.1	30.0	26.4	43.1	25.1	24.0	40.0
1,062	1,144	867	1,036	1,023	1,015	1,044	955
14.1	11.1	3.3	5.7	6.3	4.7	3.5	4.0
2.1	4.0	14.7	7.9	8.6	7.7	5.5	5.5
20.4	16.3	14.3	16.9	15.2	16.7	20.1	19.6
4.3	3.9	3.7	3.8	3.7	3.3	4.4	4.6
288	288	280	273	264	235	222	219
288	288	284	275	268	255	224	220
2,228	2,341	2,380	2,786	2,772	2,084	2,235	2,389
5,131	5,131	5,126	5,111	5,111	4,551	4,325	4,688
1,403	1,482	1,405	1,531	1,779	1,731	1,567	1,648
2,289	2,334	2,350	2,204	2,202	2,058	1,974	1,950
—	—	—	—	396	390	390	390
8,823	8,947	8,881	8,846	9,488	8,730	8,256	8,676
36,900	38,157	40,673	45,002	42,482	38,750	41,012	48,614

(3) In 2019 and onwards comparable EBITDA was adjusted to exclude the impact of unrealized mark-to-market gains or losses. 2018 and 2017 amounts were revised.
(4) 2016 and 2015 amounts were revised due to other revisions to EBITDA or FFO measures in the MD&A.
(5) 2012 to 2020 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 and lease liabilities including current portion + exchangeable securities - 100 per cent exchangeable preferred shares + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares and exchangeable preferred shares - cash and cash equivalents - principal portion of TransAlta OCP restricted cash / long-term debt and lease liabilities including current portion + exchangeable securities + 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 and lease liabilities including current portion + exchangeable securities - 100 per cent exchangeable preferred shares + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares and exchangeable 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 + 100 per cent interest paid on exchangeable preferred shares - 50 per cent dividends paid on preferred shares and exchangeable preferred shares / long-term debt and lease liabilities including current portion + exchangeable securities - 100 percent exchangeable preferred shares + fair value (asset) liability of hedging instruments on debt + 50 per cent issued preferred shares and exchangeable 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 liabilities - interest income - capitalized interest / interest on debt, exchangeable securities (excluding interest on exchangeable preferred shares) and lease liabilities - interest income + 50 per cent dividends paid on preferred shares and exchangeable preferred shares

Plant Summary

As at Dec. 31, 2020	Facility	Installed capacity(MW)[1]	Ownership (%)	Owned capacity (MW)[1][2]	Region	Revenue source	Contract expiry date
Thermal	Sundance, AB	1,213	100 %	1,213	Western Canada	Merchant	—
10 facilities	Keephills, AB	790	100 %	790	Western Canada	Alberta PPA[3]/ Merchant [5]	2020
	Keephills 3, AB	463	100 %	463	Western Canada	Merchant	—
	Sheerness, AB	800	25 %	200	Western Canada	Alberta PPA / Merchant [6]	2020
	Centralia, WA	1,340	100 %	1,340	United States	LTC[7] / Merchant	2020-2025 [8]
Total Thermal		4,606		4,006			
Gas	Poplar Creek, AB[9]	230	100 %	230	Western Canada	LTC	2030
12 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
	Ada, MI [4]	29	100 %	29	United States	LTC	2026
	Parkeston, WA*[11]	110	50 %	55	Australia	LTC	2026
	Southern Cross, WA*[10][11]	245	100 %	245	Australia	LTC	2038
	South Hedland, WA* [11]	150	100 %	150	Australia	LTC	2042
Total Gas		1,527		1,316			
Wind & Battery Storage	Summerview 1, AB*	68	100 %	68	Western Canada	Merchant	—
25 facilities	Summerview 2, AB*	66	100 %	66	Western Canada	Merchant	—
	Ardenville, AB*	69	100 %	69	Western Canada	Merchant	—
	Blue Trail and Macleod Flats, AB*	69	100 %	69	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	—
	WindCharger battery storage, AB*	10	100 %	10	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
	Skookumchuck, WA [4]	137	49 %	67	United States	LTC	2040
Total Wind		1,694		1,523			
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		8,796		7,791			

** TransAlta Renewables Inc. facility.*
(1) Megawatts are rounded to the nearest whole number; columns may not add due to rounding.
(2) Includes 100% of TransAlta Renewables assets. As of Dec. 31, 2020, TransAlta owns approximately 60% of the outstanding shares of TransAlta Renewables.
(3) PPA refers to Power Purchase Arrangement. Alberta PPAs expired on Dec. 31, 2020. As of Jan. 1, 2021 the facilities are operating as merchant.
(4) Effective Jan. 1, 2021, facility has been sold to TransAlta Renewables.
(5) Merchant capacity includes a 12 MW uprate on units 1 and 2, which began operation in the second quarter of 2012.
(6) Merchant capacity includes a 10 MW uprate completed in the first quarter of 2016.
(7) LTC refers to Long-Term Contract.
(8) Contract is in place until 2025; however Centralia Unit 1 was retired from service effective Dec. 31, 2020, and capacity decreased to 670 MW on Jan. 1, 2021.
(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	2020	2019	2018
Facilities with ISO 14001 and/or OHSAS 18001-based management systems *(percentage)*[1]	97	97	97
Management system audits[2]	8	12	17

Environmental Performance[3]	2020	2019	2018
Resource or energy use[4]			
Coal combustion (tonnes)	6,637,000	9,092,000	10,001,000
Natural gas combustion (GJ)	83,046,000	77,007,000	62,355,000
Diesel combustion (L)	6,954,000	10,179,000	9,553,000
Gasoline consumption: vehicle (L)	935,000	1,099,000	1,408,000
Diesel consumption: vehicle (L)	10,976,000	21,531,000	38,361,000
Propane consumption: vehicle (L)	5,000	96,000	75,000
Electricity: building operations (MWh)	188,000	226,000	273,000
Natural gas: building operations (GJ)	48,000	52,000	71,000
Propane: building operations (L)	190,000	177,000	170,000
Kerosene: building operations (L)	48,000	84,000	116,000
Total resource or energy use (GJ)[5]	**279,027,000**	**345,609,000**	**358,435,000**
Greenhouse gas emissions[6]			
Carbon dioxide (tonnes CO_2e) √	16,264,000	20,436,000	20,596,000
Methane (tonnes CO_2e) √	36,000	51,000	69,000
Nitrous oxide (tonnes CO_2e) √	80,000	111,000	115,000
Sulphur hexafluoride (tonnes CO_2e)	110	2,000	10
Total greenhouse gas emissions[7] (tonnes CO_2e) √	**16,380,000**	**20,599,000**	**20,781,000**
Greenhouse gas emission intensity[8] (tonnes CO_2e / MWh) √	*0.67*	*0.75*	*0.77*
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[9]			
Total sulphur dioxide emissions (tonnes) √	12,000	16,000	19,000
Sulphur dioxide emission intensity[10] (kg / MWh) √	*0.49*	*0.58*	*0.73*
Total nitrogen oxide emissions (tonnes) √	21,000	26,000	29,000
Nitrogen oxide emission intensity[10] (kg / MWh) √	*0.88*	*0.96*	*1.08*
Total particulate matter emissions (tonnes) √	5,000	8,000	8,000
Particulate matter emission intensity[10] (kg / MWh) √	*0.20*	*0.28*	*0.32*
Total mercury emissions (kilograms) √	60	60	70
Mercury emission intensity[10] (mg / MWh) √	*2.34*	*2.36*	*2.51*

Environmental Performance *(continued)*	2020	2019	2018
Water management[11]			
Water withdrawal –water utility/municipality/customer (million m^3)	–	–	–
Water withdrawal –surface water (million m^3)	*240*	*260*	*250*
Water withdrawn –all sources (million m^3) √	240	260	250
Water discharge –all sources (million m^3) √	200	220	210
Water consumption (million m^3) √	40	**40**	**40**
Water intensity (m^3/MWh)[12] √	*1.50*	*1.55*	*1.40*
Waste management			
Non-hazardous[13]			
Landfill (tonnes) √	1,000	1,000	2,000
Landfill (L) √	39,000	35,000	68,000
Ash disposal: mine (tonnes) [14] √	408,000	641,000	715,000
Ash disposal: lagoon (tonnes) [15] √	98,000	117,000	277,000
Recycled (tonnes) [16] √	6,000	2,000	1,000
Recycled (L) √	1,869,000	3,605,000	3,722,000
Reuse (tonnes)[17] √	533,000	746,000	740,000
Storage (tonnes) √	53,000	–	–
Compostable (tonnes) √	10	N/A	N/A
Hazardous[18]			
Landfill (tonnes) √	30	60	10
Landfill (L) √	58,000	53,000	45,000
Recycled (tonnes) √	20	80	170
Recycled (L) √	20,220,000	18,931,000	16,257,000
Land use and reclamation			
Land used in mining activities – disturbed (cumulative hectares) √	12,600	12,600	12,400
Land used in mining activities – reclaimed (cumulative hectares) √	4,800	4,800	4,700
Land reclamation (% of land disturbed) √	*38*	***38***	***38***
Land used in mining activities: disturbed minus reclaimed (hectares) √	7,700	7,700	7,700
Land used by facilities, offices and equipment (hectares) √	3,900	3,900	3,900
Total land use (cumulative hectares) √	11,700	**11,700**	**11,700**
Environmental incidents[19]			
Total environmental incidents √	8	9	7
Significant environmental incidents	6	3	1
Regulatory non-compliance environmental incidents	2	6	6
Environmental enforcement actions[20]	–	1	1
Environmental fines ($ thousands)	–	4	6
Spills[21]			
Volume of significant spills (m^3)	4	530	5

Social Performance	2020	2019	2018
Workplace practices			
Employees	1,476	1,543	1,883
Number of full-time employees	*1,392*	*1,471*	*1,810*
Number of part-time employees	*16*	*18*	*22*
Number of contingent employees	*68*	*54*	*51*
Employees represented by independent trade union organizations[22] (%)	41	45	50
Voluntary employee turnover rate[23] (%)	9.05	13.59	20.22
Diversity			
Women in workforce (% of all employees)	21	20	20
Women in senior management (%)	43	50	50
Women on Board of Directors (%)	45	33	40
Health and safety			
Health and safety enforcement actions[24]	–	3	–
Health and safety fines ($ thousands)	–	–	–
Employee & contractor fatalities √	–	–	–
Lost-time incident (LTI) (absence from work)[25] √	5	5	1
Medical aid (MA) incidents (no absence from work)[26] √	9	7	12
Restricted Work Injuries (RWI) incidents (no absence from work)[27] √	2	3	12
First Aid (FA) incidents (no absence from work)[28] √	17	8	23
Total injuries to employees & contractors √	33	23	48
Exposure hours [29]	3,948,000	4,108,000	5,014,000
Total Injury Frequency (TIF) (employees and contractors)[30] √	1.67	1.12	1.91
Total Recordable Injury Frequency (TRIF) (employees and contractors)[31]	0.81	0.73	1.00
Community relations			
Community investments ($ millions)[32]	2.2	2.1	2.4

√ 2020 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 Best Practice Sustainability Reporting Frameworks

The following outlines our sustainability or ESG performance indicator alignment with key criteria of the Global Reporting Initiative ("GRI") and Sustainability Accounting Standards Board ("SASB").

Environment Health & Safety Management Systems	GRI Standards	SASB Standards
Facilities with ISO 14001 and/or OHSAS 18001-based management systems *(percentage)*		
Management system audits		

Environmental Performance	GRI Standards	SASB Standards
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	IF-EU-110a.1
Methane (tonnes CO_2e)	305-1, 305-2	IF-EU-110a.1
Nitrous oxide (tonnes CO_2e)	305-1, 305-2	IF-EU-110a.1
Sulphur hexafluoride (tonnes CO_2e)	305-1, 305-2	IF-EU-110a.1
Total greenhouse gas emissions (tonnes CO_2e)	305-1, 305-2	**IF-EU-110a.1**
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)		

Environmental Performance *(continued)*	GRI Standards	SASB Standards
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)	303-5	**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)	304-3	
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 Standards	SASB Standards
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)	403-9	IF-EU-320a.1
Medical aid (MA) incidents (no absence from work)	403-9	IF-EU-320a.1
First Aid (FA) incidents (no absence from work)	403-9	
Restricted Work Injuries (RWI) incidents (no absence from work)	403-9	IF-EU-320a.1
Total injuries to employees & contractors	403-9	IF-EU-320a.1
Exposure hours	403-9	IF-EU-320a.1
Total Injury Frequency (TIF) (employees and contractors)	403-9	
Total Recordable Injury Frequency (TRIF) (employees and contractors)	403-9	IF-EU-320a.1
Community relations		
Community investments ($ millions)	201-1	

Discussion and Notes on Numbers

TransAlta continually strives to improve the accuracy and scope of our sustainability performance data. We continually 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 75 facilities.*
2. *Internal audits are conducted against ISO management systems, regulatory frameworks and the Alberta Certificate of Recognition standard.*
3. *Historical environmental performance figures have been rounded based on the following methodology: i) All environmental data are rounded to the nearest one thousand except where values are <100, in which case they are rounded to the nearest 10; ii) Land use data, which is smaller in magnitude compared with other environmental indicators, is rounded to the nearest 100 to represent a more accurate picture of management and progress.*
4. *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.*
5. *A number of 2018 and 2019 historical energy use volumes from our wind & solar, hydro, Alberta thermal and natural gas business segments were revised in 2020. Minor adjustments were made to 2019 volumes for natural gas combustion, diesel combustion, propane use (for building operations and vehicle use), diesel use for vehicles, gasoline use for vehicles, natural gas use for buildings and electricity use for building operations. Minor adjustments were made to 2018 volumes for diesel use for vehicles, gasoline use for vehicles, propane use for building operations, natural gas use for buildings and electricity use for building operations. A number of 2019 changes were a result of accrual adjustments from the previous year. Changes to 2018 and 2019 data were also a result of process improvement changes - in 2020 we incorporated a number of remote offices into our reporting boundary. Although these offices are small and associated energy use is minor, these revisions did adjust historical totals for gasoline and diesel vehicle use, electricity, gas and propane use in building operations in 2018 and 2019. These adjustments also resulted in a change to our reported total energy use volumes in 2018 and 2019.*
6. *GHG emissions are calculated and reported from TransAlta-operated facilities in line with carbon compliance regulations from the geographic jurisdiction where the facility is located. For GHG emissions that are not calculated using jurisdictional carbon compliance guidance we follow guidance from 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 2020 MD&A and our 2020 CDP climate change report. Global warming potentials can vary with respect to regional compliance guidance. We compile our corporate GHG inventory using our business segment GHG calculations. The Clean Energy Regulator in Australia amended global warming potentials in August of 2020 and the use of global warming potentials in our Australia Gas GHG calculations differ from the rest of our fleet as a result of these amendments. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.*
7. *Gross GHG emissions or gross carbon dioxide equivalent (CO_2e) emissions is the sum of carbon dioxide, methane, nitrous oxide and sulphur hexafluoride (SF_6). 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 2018 and 2019 GHG emissions data primarily from our wind & solar, hydro and natural gas business segments as a result of adjusted historical energy use volumes. A minor adjustment was made to 2019 SF_6 emissions as a result of an internal discrepancy at our Sarnia facility. An SF_6 leak from late in 2019 was not reported in our system until 2020.*
8. *GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership.*
9. *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 GHG 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}. Historical 2018 and 2019 NO_x incurred minor revisions in 2020 to include NO_x emissions from our Highvale facility. The revision increased 2018 NO_x from 28,000 to 29,000 tonnes. Minor revisions were made to 2018 and 2019 air emissions data at our Highvale facility and natural gas facilities in Ontario. The 2019 changes were as a result of accrual adjustments from the previous year. Changes to 2018 and 2019 data were also a result of process improvement changes - including conducting more precise calculations in 2020, such as for TPM emissions due to road dust at our Highvale facility.*
10. *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 2018 and 2019 air emissions data (see Note 9) resulted in minor adjustments to air emission intensity data.*
11. *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 GHG 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. Water use at our new Ada facility was not reported in 2020 as it was acquired in August of 2020. The integration of water for ESG reporting will occur in 2021. Given the size of Ada, 29 MW (relatively small), we anticipate a minor impact to overall water consumption. Minor revisions were made to 2018 and 2019 water use data at our Ottawa facility, head office, and wind & solar business segment due to accruals and internal discrepancies, which did not affect reported totals. Leinster 2018 and 2019 water data were revised as a result of an internal discrepancy affecting the withdrawal amount, but reported totals were not affected. Centralia 2019 water data was revised in 2020 as a result of identified discrepancies, which resulted in overreported raw water intake or water withdrawal for sustainability reporting. The issue was specific to 2019 data only. Water from our Centralia facility is also reported to the Department of Ecology ("DOE") in Washington State. There were no issues with our data submitted to the DOE, as the information generated for sustainability reporting followed a separate data collection process. As a result, Centralia 2019 water withdrawal was revised from approximately 52 million m^3 to 26 million m^3. The Centralia business unit has performed a full review of its water reporting process and our corporate function will review its internal assurance process to support avoidance of any future reoccurrence of this event.*
12. *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. Water intensity was not tracked for our Ada facility in 2020 as it was acquired in August of 2020 but will be tracked in 2021. Historical adjustments to 2019 water use data (see Note 11) resulted in adjustments to 2019 water intensity data.*
13. *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. Adjustments were made to historical 2019 landfill (tonnes) and landfill (L) waste volumes to reflect accrued volumes from 2019. Adjustments were made to historical 2018 recycled (tonnes) and recycled (L). Changes to 2018 and 2019 data were also a result of process improvement changes - in 2020 we incorporated a number of remote offices into our reporting boundary.*
14. *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.*
15. *Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.*
16. *In 2020, we revised our categorization of waste. As a result our reported 2018 and 2019 non-hazardous recycled (tonnes) were adjusted. Specifically, volumes of fly ash waste from our Sundance and Keephills facilities were recategorized to non-hazardous reuse (tonnes). This decreased our total for non-hazardous recycled (tonnes).*
17. *In 2020, we revised our categorization of waste. As a result our reported 2018 and 2019 non-hazardous reuse (tonnes) were adjusted. Specifically, volumes of fly ash waste from our Sundance and Keephills facilities were recategorized as non-hazardous recycled (tonnes) to non-hazardous reuse (tonnes). This increased our total for non-hazardous recycled (tonnes). In 2020, an internal discrepancy was noted in 2018 non-hazardous recycled (tonnes) at our Sundance facility and the value was changed from 178.6 tonnes to 178,558 tonnes. This revision resulted in an increase to non-hazardous reuse (tonnes) totals. We define reuse as waste that we are able to sell to a third party for use.*
18. *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. Historical 2018 and 2019 hazardous recycled (L) and landfill (tonnes) waste volumes were adjusted in 2020 to reflect data system errors at our gas and renewables business unit. Historical recycled (tonnes) from 2018 were reported as 200 tonnes in 2019 due to rounding. The actual amount was 166 tonnes. In 2020, we have reported this volume as 170 tonnes to follow our new rounding methodology.*
19. *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.*
20. *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.*
21. *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 could adversely impact the environment and the Corporation.*
22. *TransAlta has approximately 600 unionized workers working primarily in our operational business units.*
23. *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.*
24. *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.*
25. *Lost-time injuries (LTIs) are injuries that resulted in the worker being away from work beyond the day of the injury.*
26. *Medical aids (MAs) are injuries that resulted in medical treatment beyond first aid.*
27. *Restricted work injuries (RWIs) are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.*
28. *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.*
29. *Exposure hours are total hours worked by all TransAlta employees and contractors.*
30. *Total Injury Frequency (TIF) tracks the total number of injuries (medical aids, lost-time injuries, restricted works and first aids) per 200,000 hours worked.*
31. *Total Recordable Injury Frequency (TRIF) measures restricted work, medical aid and lost-time injuries per 200,000 hours worked.*
32. *Cumulative of donations and sponsorship totals in the respective calendar year. This investment figure does not include donations from our employees.*

Independent Practitioner’s Assurance Report

To the Board of Directors and Management of TransAlta Corporation (“TransAlta”)

Scope of EY Engagement

We have been engaged by TransAlta to perform a ‘limited assurance engagement’, as defined by International Standards on Assurance Engagements, here after referred to as the engagement, over selected sustainability performance indicators as reported in TransAlta’s Annual Integrated Report (the “Report”) for the calendar year ending December 31, 2020. The scope of our engagement, as agreed with management, included the following performance indicators:

- Carbon dioxide emissions (tonnes CO_2e)
- Methane emissions (tonnes CO_2e)
- Nitrous oxide emissions (tonnes CO_2e)
- Total greenhouse gas emissions and emissions intensity (tonnes CO_2e, tonnes CO_2e/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 m^3)
- Water discharge (million m^3)
- Water consumption and consumption intensity (million m^3, m^3/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 injury frequency for employees and contractors (injuries/200,000 hours)
- Total environmental incidents

The selected performance indicators are collectively referred to as the “Subject Matter” and are presented under the section Sustainability Performance Indicators of the Report on pages 248 to 250.

Other than as described in the preceding paragraph, which sets out the scope of the engagement, our assurance engagement does not extend to any other information included in, or linked to from, the Report and accordingly, we do not express a conclusion on this other information.

Criteria applied by TransAlta

In preparing the Subject Matter, TransAlta applied relevant guidance in accordance with industry standards and as well as internally and externally developed criteria (together, the “Criteria”). The internally and externally developed criteria are identified in the Report on pages 251 to 253. The internally developed Criteria were specifically designed for the preparation of the Report. As a result, the Subject Matter information may not be suitable for another purpose.

TransAlta's Responsibilities

TransAlta’s management is responsible for selecting the Criteria and for presenting the Subject Matter in accordance with that Criteria, in all material respects. This responsibility includes establishing and maintaining internal controls, maintaining adequate records and making estimates that are relevant to the preparation of the Subject Matter, such that it is free from material misstatement, whether due to fraud or error.

EY's Responsibilities

Our responsibility is to express a conclusion on the presentation of the Subject Matter based on evidence we have obtained.

We conducted our engagement in accordance with the International Standard for Assurance Engagements Other Than Audits or Reviews of Historical Financial Information (‘ISAE 3000’). This standard requires that we plan and perform our engagement to obtain limited assurance about whether, in all material respects, the Subject Matter is presented in accordance with the Criteria, and to issue a report. The nature, timing, and extent of the procedures selected depend on our judgment, including an assessment of the risk of material misstatement, whether due to fraud or error.

We believe that the evidence obtained is sufficient and appropriate to provide a basis for our limited assurance conclusions.

Our independence and quality control

We have complied with the relevant rules of professional conduct / code of ethics applicable to the practice of public accounting and related to assurance engagements, issued by various professional accounting bodies, which are founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality, and professional behavior.

The firm applies Canadian Standard on Quality Control 1, Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements, and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

Description of procedures performed

Procedures performed in a limited assurance engagement vary in nature and timing from, and are less in extent, than for a reasonable assurance engagement. Consequently, the level of assurance obtained in a limited assurance engagement is substantially lower than the assurance that would have been obtained had a reasonable assurance engagement been performed. Our procedures were designed to obtain a limited level of assurance on which to base our conclusion and do not provide all the evidence that would be required to provide a reasonable level of assurance.

Although 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. Our procedures did not include testing controls or performing procedures relating to checking aggregation or calculation of data within IT systems. A limited assurance engagement consists of making inquiries, primarily of persons responsible for preparing the Subject Matter and related information, and applying analytical and other appropriate procedures.

Our procedures included:

- Inquiries of a selection of management to gain an understanding of TransAlta's processes, policies and controls in place related to the Subject Matter;
- Inquiries of relevant staff who are responsible for the Subject Matter including, where relevant, observing and inspecting systems and processes for data aggregation and reporting;
- Evaluating the accuracy of calculations performed, on a sample basis, through analytical procedures and limited reperformance;
- Assessing risk of material misstatement due to fraud or errors relating to the selected performance indicators; and,
- Evaluating the presentation of the Subject Matter in the Report, including consistency of the Subject Matter.

We also performed such other procedures as we considered necessary in the circumstances.

Inherent limitations

Non-financial information, such as the Subject Matter, is subject to more inherent limitations than financial information, given the more qualitative characteristics of the subject matter and the methods used for determining such information. The absence of a significant body of established practice on which to draw allows for the selection of different but acceptable evaluation techniques which can result in materially different evaluation and can impact comparability between entities and over time.

Moreover, 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 indicators, and any site-specific information;
- Management's forward-looking statements; and,
- Any comparisons made by TransAlta against historical data.

Emphasis of matter – Restated comparative information

We draw attention to Notes 11, 16 and 17 on page 254, which explains that certain comparative information presented for the year ended December 31, 2020 has been restated. Our conclusion is not modified in respect of this matter.

Conclusion

Based on our procedures and the evidence obtained, nothing has come to our attention that causes us to believe that the selected performance indicators as reported in the Report for year-end December 31st, 2020 are not prepared, in all material respects, in accordance with the Criteria.

Ernst & Young LLP

March 2, 2021
Calgary, Canada

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 2020

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2020	March 2, 2020	Feb. 28, 2020	$0.0425
July 1, 2020	June 1, 2020	May 29, 2020	$0.0425
Oct.1, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.0425
Jan. 1, 2021	Dec. 1, 2020	Nov. 30, 2020	$0.0425
April 1, 2021	March 1, 2021	Feb. 26, 2021	$0.0450

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 Sept. 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 Sept. 30, 2019, to, but excluding,Sept. 30, 2024.

Preferred Share Dividends Declared in 2020

Series A

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2020	March 2, 2020	Feb. 28, 2020	$0.16931
June 30, 2020	June 1, 2020	May 29, 2020	$0.16931
Sept. 30, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.16931
Dec. 31, 2020	Dec. 1, 2020	Nov. 30, 2020	$0.16931
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.16931

Series B

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2020	March 2, 2020	Feb. 28, 2020	$0.22949
June 30, 2020	June 1, 2020	May 29, 2020	$0.22800
Sept. 30, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.14359
Dec. 31, 2020	Dec. 1, 2020	Nov. 30, 2020	$0.13693
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.13186

Series C

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2020	March 2, 2020	Feb. 28, 2020	$0.25169
June 30, 2020	June 1, 2020	May 29, 2020	$0.25169
Sept. 30, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.25169
Dec. 31, 2020	Dec. 1, 2020	Nov. 30, 2020	$0.25169
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.25169

Series E

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2020	March 2, 2020	Feb. 28, 2020	$0.32463
June 30, 2020	June 1, 2020	May 29, 2020	$0.32463
Sept. 30, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.32463
Dec. 31, 2020	Dec. 1, 2020	Nov. 30, 2020	$0.32463
March 31, 2021	March 1, 2021	Feb. 26, 2021	$0.32463

Series G

Payment Date	Record Date	Ex-Dividend Date	Dividend
March 31, 2020	March 2, 2020	Feb. 28, 2020	$0.31175
June 30, 2020	June 1, 2020	May 29, 2020	$0.31175
Sept. 30, 2020	Sept. 1, 2020	Aug. 31, 2020	$0.31175
Dec. 31, 2020	Dec. 1, 2020	Nov. 30, 2020	$0.31175
March 31, 2021	March 1, 2021	Feb. 26, 2021	$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. The Board of Directors have also declared dividends on the Series I Preferred Shares, which are held by by an affiliate of Brookfield Renewable Partners.

Voting Rights

Common shareholders receive one vote for each common share held.

Annual Meeting

The Annual and Special Meeting of Shareholders will be held in a virtual-only meeting format at 12:00 noon Calgary time, on Tuesday, May 4, 2021.

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 *($)*

	11	12	13	14	15	16	17	18	19	20
TransAlta	100	77	74	62	31	49	50	38	65	69
S&P/TSX	100	107	121	134	123	149	162	148	182	192

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2011 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)*

	11	12	13	14	15	16	17	18	19	20
Market Value	21.02	15.12	13.48	10.52	4.91	7.43	7.45	5.59	9.28	9.67
Book Value	12.08	8.78	7.92	8.52	8.52	8.92	8.28	7.16	7.14	5.13

Data is from 2011 onwards.

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2020

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	12	20	46	18	16	13	8	11	16	11	14	13
TSX closing price *($ per share)*	9.88	10.05	7.36	8.19	8.05	8.05	8.76	8.38	8.19	7.90	9.00	9.67

Source: FactSet

Return on Common Shareholders' Equity

(%)

	11	12	13	14	15	16	17	18	19	20
ROE	10.6	(25.9)	(3.2)	6.3	(1.2)	5.4	(10.0)	(15.8)	3.3	(30.3)

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 and 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 who wish to report 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
Executive Vice President, Finance and Chief Financial Officer
President of TransAlta Renewables Inc.

Jane N. Fedoretz
Executive Vice President, People, Talent & Transformation

Brett M. Gellner
Chief Development Officer

John H. Kousinioris
Chief Operating Officer

Shasta R. Kadonaga
Senior Vice President, Shared Services

Kerry O'Reilly Wilks
Executive Vice President, Legal, Commercial & External Affairs

Michael J. Novelli
Executive Vice-President, Generation

Aron J. Willis
Executive Vice-President, Growth

Blain Van Melle
Executive Vice-President, Alberta Business

Kathryn Higgins
Managing Director and Corporate Controller

Brent Ward
Senior Vice President, M&A, Strategy & Treasurer and Chief Financial Officer of TransAlta Renewables Inc.

Scott T. Jeffers
Managing Director, Legal, Sustainability and Corporate Secretary

Glossary of Key Terms

Alberta Electric System Operator (AESO)
Alberta Electric System Operator; the independent system operator and regulatory authority for the Alberta Interconnected Electric System.

Alberta Hydro Assets
The Corporation's hydroelectric assets located in Alberta consisting of the Barrier, Bearspaw, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray, Three Sisters, Bighorn and Brazeau hydro facilities.

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

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.

AUC
Alberta Utilities Commission.

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.

Carbon Tax
Sets a carbon price per tonne of GreenHouse Gas emissions related to transportation fuels, heating fuels and other small emission sources.

Capacity
Generation equipment's rated, continuous load-carrying ability, expressed in megawatts.

Cash-Generating Unit (CGU)
A cash-generating unit 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.

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.

Disclosure Controls and Procedures (DC&P)
Refers to controls and other procedures designed to ensure that information required to be disclosed in the reports filed by the Corporation or submitted 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 the Corporation in its reports that it files or submits under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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

Environmental Management Systems (EMS)
A set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency.

Emission Performance Standards (EPS)
Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

EPCs
Emission Performance Credits.

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.

Free Cash Flow (FCF)
Amount of cash generated by the Corporation through its operations (cash from operations) minus the funds used by the Corporation for the purchase improvement, or maintenance of the long-term assets to improve the efficiency or capacity of the Corporation (capital expenditures).

Funds from Operations (FFO)
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.

Full Notice to Proceed (FNTP)
Written notice given to the contractor fully authorizing them to proceed with the work.

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 .

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.

Global Reporting Initiative (GRI)
The world's most widely used sustainability standards. An independent, international organization that helps businesses and other organizations take responsibility for their impacts by providing them with the global common language to communicate those impacts.

Heat rate
A measure of conversion, expressed as British thermal units per Megawatt hour, of the amount of thermal energy required to generate electrical energy.

IFRS
International Financial Reporting Standards.

KPIs
Key Performance Indicators.

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.

MoA
Memorandum of Agreement.

NCIB
Normal Course Issuer Bid.

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.

OCI
Other Comprehensive Income.

OBPS
Output- Based Pricing Standard

OM&A
Operations, maintenance and administration costs

Pioneer Pipeline
The Pioneer gas pipeline jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd.

Power Purchase Agreement (PPA)
A long-term agreement established by regulation for the sale of electric energy to PPA buyers.

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.

PP&E
Property, plant and equipment.

REC
Renewable Energy Credits.

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

Sustainability Accounting Standards Board (SASB)
Connects businesses and investors on the financial impacts of sustainability. SASB Standards identify the subset of ESG issues most relevant to financial performance in each of the 77 covered industries.

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

Task Force on Climate-related Financial Disclosures (TCFD)
Designed to solicit consistent, decision-useful, forward-looking information on the material financial impacts on climate-related risks and opportunities, including those related to the global transition to a low-carbon economy. They are adopted by all organizations with public debt or equity in G20 jurisdictions for use in mainstream financial filings.

Total Injury Frequency (TIF)
Safety metric that tracks the total number of injuries, including minor first aids, relative to exposure hours worked.

Total Recordable Injury Frequency (TRIF)
Tracks the number of more serious injuries and excludes minor first aids, relative to exposure hours worked.

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 online.

United Nations Sustainable Development Goals (UN SDGs)
The Sustainable Development Goals are the blueprint to achieve a better and more sustainable future for all. They address the global challenges we face, including poverty, inequality, climate change, environmental degradation, peace and justice.

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

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

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

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

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