transalta™

2022 Integrated Report

Energizing the Future.

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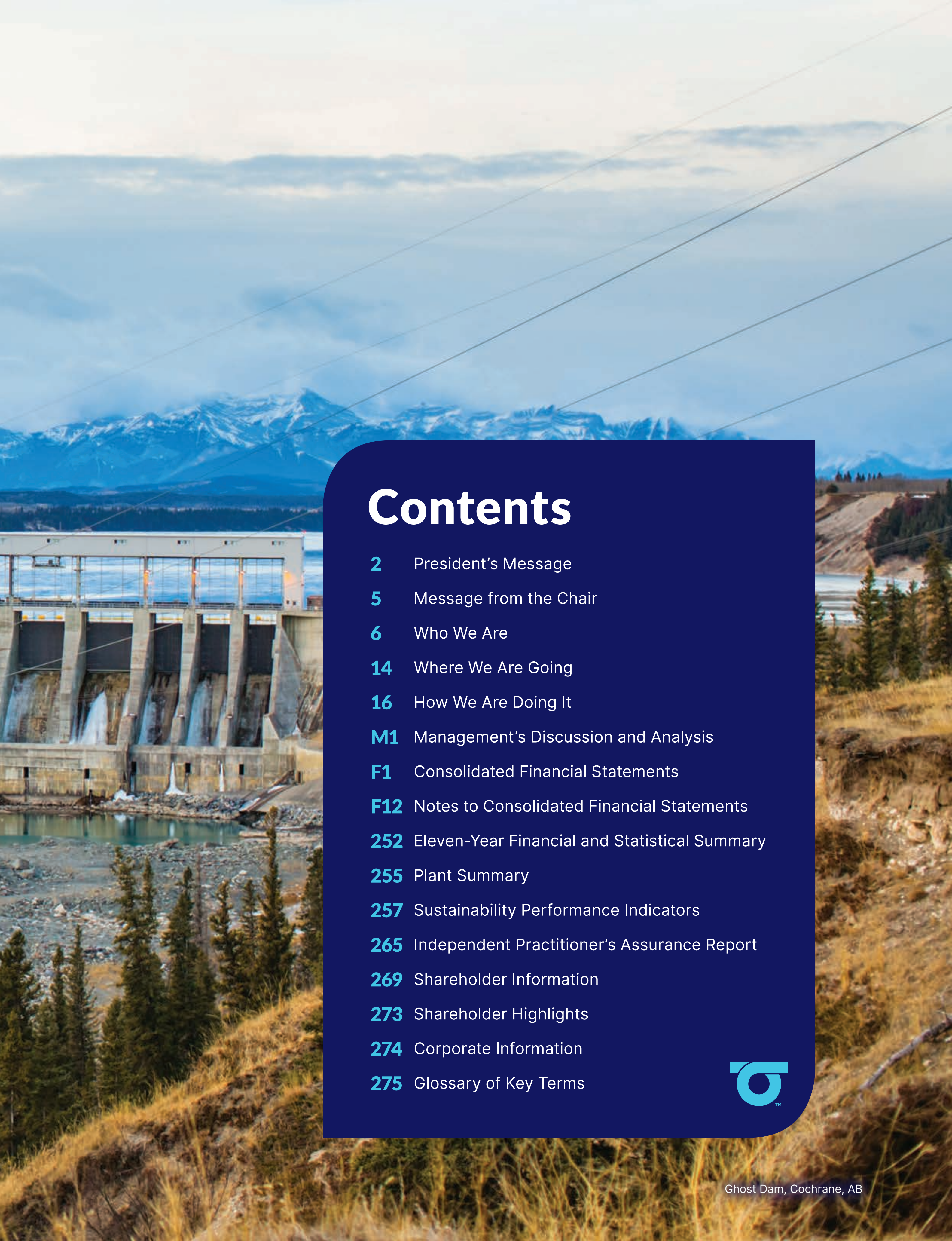


Ghost Dam, Cochrane, AB

John Kousinioris
President and Chief Executive Officer

In the fall of 2021, our executive team shared a vision for the evolution of TransAlta and launched our *Clean Electricity Growth Plan* at our investor day. We plotted a course to reposition the company towards contracted renewable generation, minimize our exposure to regulatory and carbon risk, and diversify the company's merchant position in Alberta. We laid out a plan with a clear focus on capitalizing our cash flow generation from the company's unique legacy fleet in both Alberta and Centralia, and investing those cash flows towards the expansion and diversification of our contracted renewables fleet to drive shareholder value. I am pleased to say that our legacy generating fleet has performed well and has positioned our company to fund its transition to contracted renewables growth. Our strategy is on track and is delivering consistent with our expectations. Our vision of being a customer-centred leader in clean electricity committed to a sustainable future remains firm and achievable.

Global Leader in Carbon Reductions

Today, we are on solid ground financially with a strategy that is aligned with, and resilient to, the overall rapid pace of decarbonization which we are witnessing globally and which continues to drive growing demand for renewable electricity. As countries move to set ever more stringent greenhouse gas regulations and commitments, and as companies and consumers demand low-carbon energy sources, we are positioning ourselves as a leader in renewable and hybrid generation. We believe that over the next 10 years, electrification will be critical to lowering the carbon intensity of all that is produced by our customers and communities. We are working side-by-side with our customers, and in particular those in hard-to-decarbonize industries like petrochemicals and mining, to create innovative power solutions to achieve significant reductions in carbon emissions. We are leaders in carbon reduction our company has reduced GHG emissions by 68 per cent since 2015—a remarkable milestone. Our carbon reductions alone have contributed to approximately 10 per cent of Canada's Paris Agreement target. We have been recognized by ESG rating agencies with an A rating from MSCI and an A- rating from CDP. We are continually evaluating our progress and this year we are also pleased to announce that we have accelerated our long-term decarbonization goal by adopting a net-zero by 2045 target.

As I look back on 2022, the events that disrupted global energy markets brought to the forefront—and into sharp focus—the need for balancing the three-legged stool of clean, reliable and affordable electricity. This is the foundation that we focus on as we look at what customers and consumers need as we move towards net zero. We believe that all forms of generation will be required as we transition to a cleaner future and, uniquely, we have the capabilities to build and operate across all forms of generation technologies and platforms in Canada, the United States and Australia. We are making various investments in hydrogen and other areas to ensure we keep abreast of technologies as they evolve. Our plan includes a commitment to invest $3.6 billion in clean generation growth, and more importantly, our plan is funded and in execution.

Exceptional Business Performance

During the year, we successfully navigated market challenges and delivered exceptional results, exceeding the top end of our revised guidance. Our free cash flow per share of $3.55, a 64 per cent increase compared to 2021, is a remarkable result. The strong operational performance of our fleet enabled us to successfully supply generation when the market needed it most and benefitted from the strong power prices experienced in Alberta. Our results demonstrate the value of our strategically diversified fleet in Alberta. Although we are nearing the peak of a supply cycle as more supply enters the Alberta market, we continue to believe we have the right fleet to be the energy provider of choice. With our fast-ramping hydro and our low-investment converted gas assets, we can provide cost-effective reliability when the market needs it.

In 2022, we operated without any lost-time injuries across our global operations and delivered a

Total Recordable Injury Frequency (TRIF) rate across the entire fleet of 0.39, an outstanding result and our best outcome ever. Availability was also excellent across our facilities, at 90.0 per cent fleet-wide in 2022 as compared to 86.6 per cent in 2021.

We continue to maintain a strong financial position with over $2.1 billion in liquidity and are well positioned to deliver on our *Clean Electricity Growth Plan*. We increased our annual dividend by 10 per cent to $0.22 per share, starting in January 2023, representing our fourth consecutive annual increase. On top of that, we returned $54 million to shareholders over the year and will continue to be supportive on share buybacks, especially during periods of weaker market pricing.

Clean Electricity Growth Plan Tracking to Delivery of 2 GW of Renewables

We remain confident in our ability to deliver on our *Clean Electricity Growth Plan* targets. In 2022, we reached final investment decision on 200 MW with the addition of Horizon Hill in the US and the Mount Keith transmission expansion in Australia. Although this was below our in-year growth target, we were successful in adding 1,980 MW of development opportunities to our growth pipeline which will set us up well for the future. For 2023, we have increased our growth target to 500 MW as we work towards our 2025 target of 2 GW.

We have 374 MW of advanced-stage projects that are a combination of wind, hydro-based storage and gas technologies, and are now in discussions with various potential offtakers regarding these opportunities. In 2022, we received Alberta Utilities Commission approval for our WaterCharger battery storage project, an innovative 180 MW energy storage project outside of Calgary using lithium-ion batteries. The project is another first-of-its kind in Alberta and will store must-run energy generated by our Hydro fleet and discharge it into the Alberta grid at times of high-peak demand. In addition, we currently have 678 MW of construction projects underway with over $1.35 billion allocated and we expect to see these projects reach the finish line throughout 2023. When combined with the 122 MW North Carolina Solar acquisition, these projects will deliver adjusted EBITDA of $149 million in 2024.

As we look forward to advancing our remaining development pipeline, we see inflationary and supply pressures mounting with associated impacts on some of our development opportunities. We have seen significant increases in turbine supply pricing and raw materials are also experiencing significant price inflation. We estimate that current build costs for new assets have increased by as much as 40 per cent compared to projects that were initiated only a year ago. Accordingly, we have increased our *Clean Electricity Growth Plan* capital target from $3 billion to $3.6 billion to reflect the new input pricing environment. However, despite the increases in capital costs, we are seeing continued robust demand for renewable energy as corporate and government sustainability commitments remain firm. PPA prices are adjusting to reflect supply and input cost pressures and, accordingly, we have also adjusted upwards our EBITDA target from $250 million to $315 million to reflect this dynamic. We continue to expect that our return requirements will remain intact for our shareholders. The recent announcements regarding the Inflation Reduction Act in the United States and the Fall Economic Statement in Canada are positive for our industry and company, and will help drive renewable energy demand in both regions.

As we carry out our growth focus, we are investing in our development team to increase our capabilities as a developer of choice and to expand, advance and convert our development pipeline.

TransAlta — the Primary Growth Vehicle

Over time, the investment strategies of TransAlta and our subsidiary, TransAlta Renewables, have converged. After extensive assessment, we clarified in December last year that TransAlta is best positioned as the primary growth vehicle for the consolidated group. TransAlta's development pipeline, balance sheet strength, continuing strong free cash flow generation and low dividend payout ratio supported our view that TransAlta Corporation was the best entity to deploy significant capital allocation to contracted renewables growth. TransAlta Renewables continues to be a critical asset for TransAlta. It will be principally focused on the sustainment of its dividend in 2023 and beyond, with growth opportunities focused on organic expansions of its existing assets through the execution of its rights of first offer with TransAlta and, potentially, through dropdowns from TransAlta that could partially offset its tax horizon. TransAlta Renewables will continue to allocate the majority of its highly contracted cash flows to dividends for its shareholders.

Continued Focus on Environmental, Social and Governance

The significance of environmental, social and governance (ESG) has increased exponentially over the past few years, being driven in large part by investors that are spending more time understanding the sustainability of future cash flows and the human side of a company. TransAlta has a long history of adopting leading sustainability practices, including more than 25 years of ESG reporting, and the implementation of voluntarily integrating sustainability reporting into our annual report since 2015.

We continue to drive industry-leading ESG practices within our Company. One area that we are focusing on is improving our cultural awareness of the Indigenous communities across our global operations. In 2022, this was a priority and I am proud to say that we completed the first year of our journey by delivering Indigenous cultural awareness training to all employees in Canada. We reached a completion rate of 100 per cent. This was important work, which will continue into 2023 as we carry out further training in the United States and Australia. This will ensure that we have a common awareness across all of our Company in order to advance our strategy with sensitivity and understanding towards the communities with whom we collaborate.

We are also on a cultural transformation journey by shifting the culture of our workplace towards a greater focus on learning, purpose and results, while striving to create a psychologically safe environment. I am particularly proud of one employee-driven initiative that brought this all together for us last year and highlights how we have progressed as an organization. A group of our employees developed a speaker series where employees from diverse backgrounds, ranging from ethnicity, race and orientation, could share their past experiences. They brought their most authentic selves and vulnerabilities to other employees across the company to promote understanding and inclusion. It was amazing to see this level of psychological safety in action at our workplace.

Preparing for 2024 and Beyond

I am spending my time in 2023 seeking ways to accelerate our growth strategy and ensure TransAlta remains resilient within our changing market and regulatory landscape. We are focused on identifying the opportunities and challenges that will push our company forward in the latter part of the decade. We will share more of our thinking at our investor day in the autumn of 2023.

2022 was truly a remarkable year for our company. Our success was a collective one and the product of the individual efforts of each TransAlta employee. It has been an honour to lead an organization of talented people with a commitment to delivering exceptional results while adhering to our core values of safety, innovation, sustainability, respect, and integrity.

I would also like to express thanks to our Board of Directors for their support, guidance and wisdom. They are committed to our company, its values and its mission to deliver the clean, reliable and affordable electricity that the world needs now and in the future.

And to our shareholders, we welcome and value your perspectives and thank you for your continuing commitment to TransAlta.

Last but definitely not least, we sincerely appreciate the support of all of our stakeholders and thank our employees for all that they do to ensure we are powering and empowering our economies and communities sustainably. I am pleased to report that there is every reason to believe that our success will continue in 2023.

John H. Kousinioris
President and Chief Executive Officer
February 22, 2023

John P. Dielwart
Chair of the Board of Directors

As we report the financial results for the year ended December 31, 2022, I cannot understate the pride I have in the management team and all the Company's employees. Over the past five years, the Company, under direction from the Board has materially reduced its corporate-level debt, expanded its renewable portfolio and retired or converted all of its Canadian coal generating assets to natural gas-eight years ahead of the mandated elimination of emissions from coal-fired generation. The Company has managed its evolution with great skill and care for the benefit of our shareholders. It is through the hard work and determination of your management team that we are in a position to report that 2022 was the best year in our operating history. We earned unprecedented performance from our investments and our management team delivered exceptional free cash flow for our shareholders. TransAlta has delivered performance at all levels: financial, operational and safety.

The Company's strategy is on point and 2022 reflects the success of that execution. We have initiated a capital allocation program where we are deploying the legacy cash flows of our transitioning merchant thermal business and unique hydro fleet toward contracted renewables in order to pivot the Company and generate long-term value for our shareholders. We have come a long way and today we are proud to say we are truly a transition company and well-positioned as a credible and sought-after developer of choice for customers. We are a clean power leader with a strong and dedicated focus on ESG; we have the carbon reduction receipts in hand. We are in the strongest financial position that we have been in years and are poised to grow where we can continue to add value to our shareholders and continue to shift our Company more heavily towards contracted renewables. It is important to state that we will not grow the business just for the sake of growth. Rates of return for renewable projects in certain jurisdictions need to be adequate to achieve our target value creation objectives. Long term shareholder value creation will drive our investment decisions and therefore dictate pace of growth.

On behalf of the Board, I would like to extend my gratitude to Ms. Beverlee Park for her long-term service and significant contributions to the Company. She has been a valuable contributor to our Board since 2015 and we thank her for the leadership she provided, especially as Chair of the Audit, Finance and Risk Committee of the Board. We wish her well in her retirement.

The upside to a Board retirement is that we are able to bring on additional talent to drive the evolution of the Company. I am excited to welcome Ms. Manjit Sharma to our Board. She brings over 30 years of experience spanning various industries and has been recognized among Canada's top executives.

I also wish to acknowledge the nomination of Ms. Candace MacGibbon to the Board. She is a new candidate director standing for election at our next annual meeting of shareholders. She brings over 25 years of experience in the mining sector and capital markets. We look forward to welcoming her to our Company following her election to the Board at our annual meeting.

Your Board is extremely proud of the achievements this year of the management team at TransAlta and grateful for the capable leadership of our President and Chief Executive Officer, John Kousinioris, and the executive leadership team. We would like to recognize all the employees of TransAlta for their tireless efforts in delivering an exceptional year in what has remained an unpredictable environment on so many levels. The team has deftly managed and reacted to the uncertainty that is now inherent in the business environment. We are also particularly proud that the team has continued to lead with our shared values, all working together to embed a winning culture. The latter was particularly evident during the Company's President's Awards recognizing the achievements of 2022 and which put on full display the values, commitment, passion and intentionality all of our employees bring to TransAlta every day.

We also send special thanks to each of our shareholders for their continuing commitment to the Company. We value your engagement and viewpoints to help form our own perspectives as to the evolution of the Company.

The Board of Directors and I will continue to guide this Company toward delivering quality performance to drive lasting shareholder value.

John Dielwart

John P. Dielwart
Chair of the Board of Directors
February 22, 2023

Who We Are

TransAlta is a Canadian corporation and one of the country's largest publicly traded power generators. We own, operate and manage a contracted and geographically diversified portfolio of assets using a broad range of fuels including hydro, wind, solar and natural gas.

Our Vision

A leader in clean electricity — committed to a sustainable future

Our Mission

Provide safe, low-cost and reliable **clean electricity**

Our Values

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

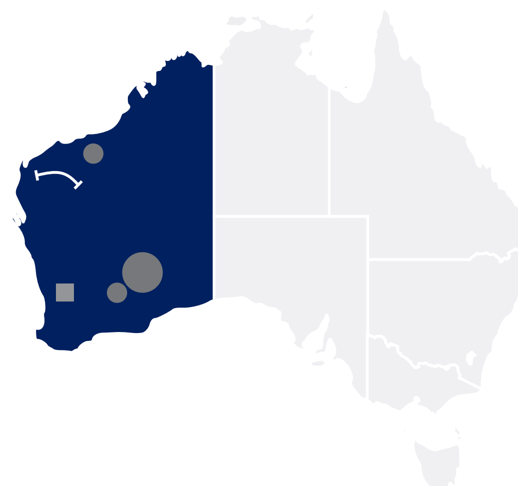
Fleet Overview

Wind and Solar
29 Facilities

Hydro
25 Facilities[1]

Natural Gas
17 Facilities

Energy Transition
1 Facility[1]



Geographic Breakdown: International Reach

Canada
We began in Alberta over 111 years ago with the construction of our first hydro facility. Today, our operations span the country, providing the electricity Canadians need every day.

1911
First plant commissioned

4,914 MW
Gross installed capacity

56 Facilities
Currently operating

Australia
TransAlta Energy Australia is building on our 20-year history in the country with significant new investments made over the past several years.

1996
First facility commissioned

450 MW
Gross installed capacity

6 Facilities
Currently operating

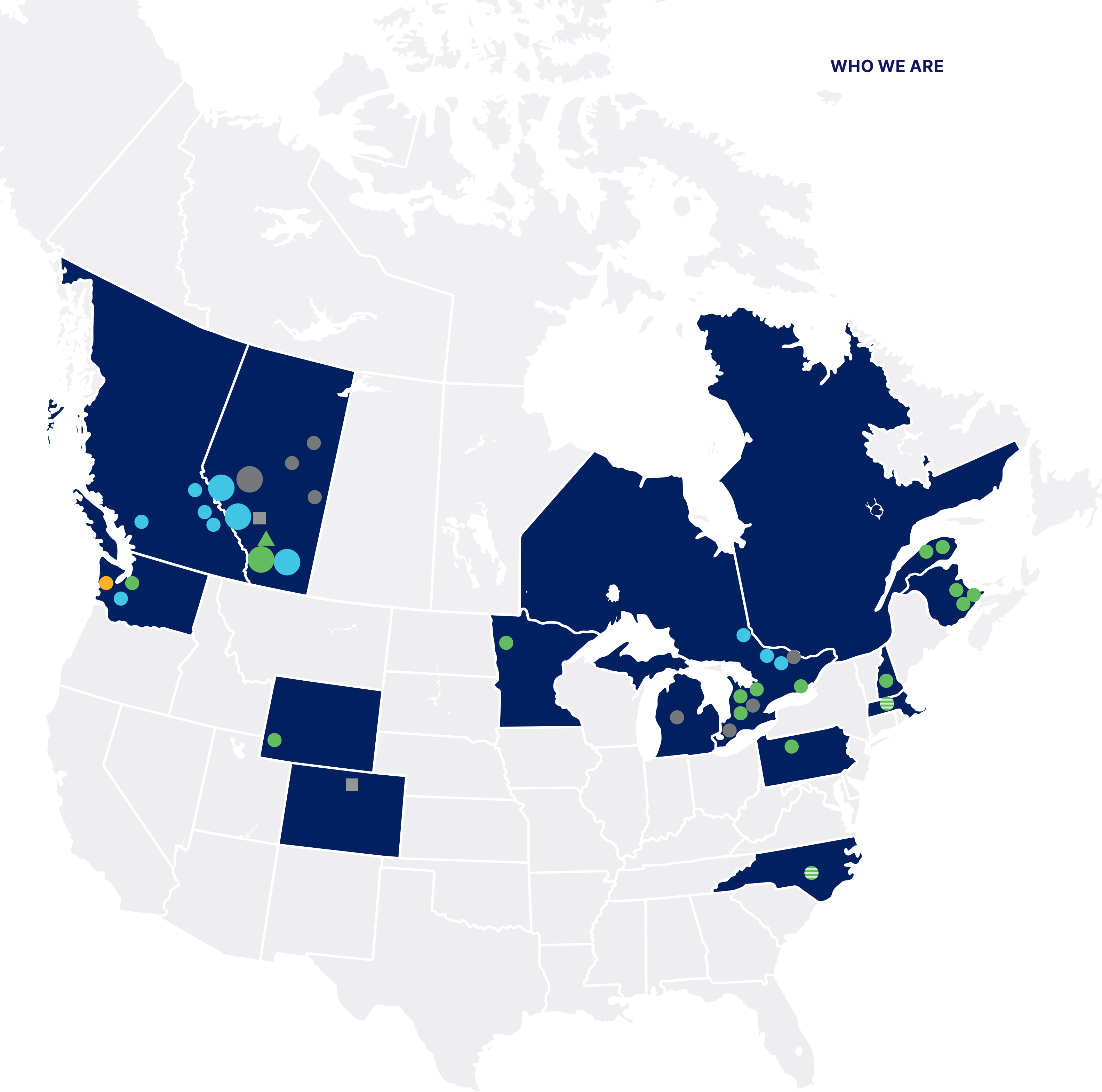
United States
Our United States operations began in Centralia, Washington. Since then, our US fleet has expanded to include gas, hydro, solar and wind generation.

2000
First facility acquired

1,219 MW
Gross installed capacity

10 Facilities
Currently operating

(1) Skookumchuck dam in Washington State has been included in the Hydro facility count.



LEGEND

Wind
Solar
Battery
Hydro
Natural Gas
Energy Transition
Pipeline
Business Development Offices

TransAlta at a Glance

TransAlta owns, operates and develops a diverse fleet of electrical generation assets in Canada, the United States and Australia. We provide municipalities, medium and large industries, businesses and utility customers with clean, affordable, energy-efficient and reliable power. Today, we are one of Canada's largest producers of wind power and Alberta's largest producer of hydro-electric power. For over a century, we've been committed to providing clean, low-cost and sustainable electricity to power local communities.

$8.9 billion

Enterprise Value
Strong balance sheet and capital discipline

111 years

Generation Experience
The foundation of our focused strategy

$3.3 billion

Market Capitalization
Listed on the TSX and NYSE

Over 1,200

Employees
Central to value creation

~6,600 MW

Diversified and Resilient Portfolio
72 generating facilities in Canada, the United States and Australia

~4+ GW

Growth Pipeline
Extensive and diversified set of growth opportunities

Awards & Recognition

TransAlta has been recognized in recent years for our performance as a responsible operator and proud community member where we work and live. Our ESG performance continues to be celebrated.

CDP Industry Leader Score of A-

This is above the North American regional average of C and represents the highest score achieved by companies in the thermal power generation sector.

Globe and Mail Board Games Rank of 26 (a score of 90 out of 100)

Board Games assesses the work of Canada's largest boards against a rigorous set of governance criteria (well beyond the minimum set by regulators).

Bloomberg Gender-Equality Index (2020, 2021 and 2022)

A market capitalization-weighted index that aims to track the performance of public companies committed to transparency in gender data reporting.

Globe and Mail Women Lead Here (2020, 2021 and 2022)

The Globe and Mail Women Lead Here list intends to set a benchmark for gender diversity in corporate Canada.

Governance Gavel Award: Best Corporate Governance Disclosure

Canadian Coalition for Good Governance awards recognize excellence in shareholder communications by issuers through their annual proxy circulars.

Energy Intelligence 2022 Green Utilities Report (2020 and 2021)

The annual Green Utilities Report ranks 100 companies among the largest power generators from around the world, accounting for almost half of global capacity.

Diversio

First publicly traded energy company to be certified by Diversio for its Equity, Diversity and Inclusion program.

The Queen's University IRC Award for Best Learning & Development Strategy

This award recognizes and celebrates the HR team that has delivered the most outstanding organizational benefits by directly linking the training needs of their people, at all levels, to the business needs of their organization.

Canadian Council for Aboriginal Business

Bronze-level Progressive Aboriginal Relations recognition of our Indigenous partnerships and relationships.

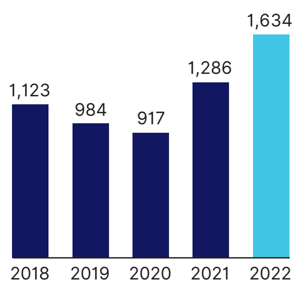
United Way

United Way "Thanks a Million Award" annual recipient since 2001.

Financial Highlights

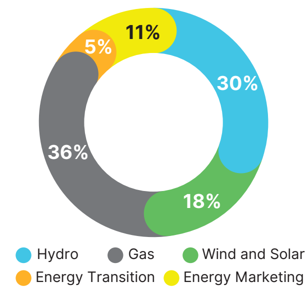
Adjusted EBITDA[1]
($ millions)

$1,634



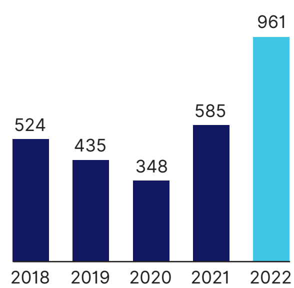
2022 Adjusted EBITDA from Generation[1,2]
($ millions)

$1,736



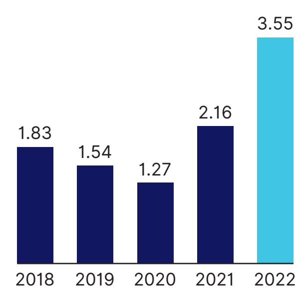
Free Cash Flow[1]
($ millions)

$961



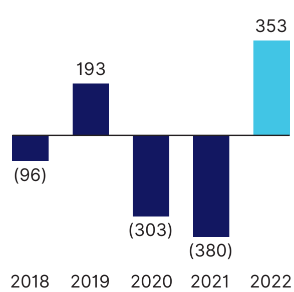
Free Cash Flow Per Share[1]

$3.55



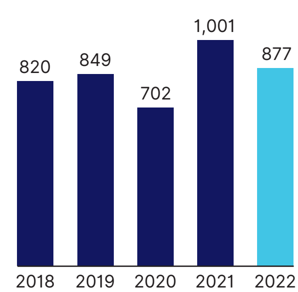
Earnings (Loss) Before Income Taxes
($ millions)

$353



Cash Flow from Operating Activities
($ millions)

$877



(1) Non-IFRS measure. See pages M40 to M50 for details.
(2) Excludes the results from the Corporate segment and our equity investments.

Hydro

Year ended Dec. 31	2022	2021	2020
Installed capacity (MW)[3]	**922**	925	925
Production (GWh)	**1,988**	1,936	2,132
Ancillary volumes (GWh)	**3,124**	2,897	2,857
Revenues[2]	**607**	383	152
Gross margin	**585**	367	144
Adjusted EBITDA[1]	**527**	322	105

Wind and Solar

Year ended Dec. 31	2022	2021	2020
Installed capacity (MW)[3]	**1,906**	1,906	1,572
Production (GWh)	**4,248**	3,898	4,069
Revenues[2]	**407**	348	334
Gross margin	**375**	331	309
Adjusted EBITDA[1]	**311**	262	248

Gas

Year ended Dec. 31	2022	2021	2020
Installed capacity (MW)[3]	**3,084**	3,084	3,084
Production (GWh)	**11,448**	10,565	10,780
Revenues[2]	**1,521**	1,126	848
Gross margin	**801**	634	507
Adjusted EBITDA[1]	**629**	488	367

Energy Transition

Year ended Dec. 31	2022	2021	2020
Installed capacity (MW)[3]	**671**	1,472	2,548
Production (GWh)	**3,574**	5,706	7,999
Revenues[2]	**724**	728	690
Gross margin	**159**	236	290
Adjusted EBITDA[1]	**86**	133	175

Energy Marketing

Year ended Dec. 31	2022	2021	2020
Revenues[2]	**218**	202	133
Adjusted EBITDA[1]	**183**	166	103

Corporate

Year ended Dec. 31	2022	2021	2020
OM&A	**(101)**	(84)	(80)
Adjusted EBITDA[1]	**(102)**	(85)	(81)

Consolidated

Year ended Dec. 31	2022	2021	2020
Installed capacity (MW)[3]	**6,583**	7,387	8,129
Total production (GWh)	**21,258**	22,105	24,980
Revenues[4]	**2,976**	2,721	2,101
Adjusted EBITDA[1]	**1,634**	1,286	917

(1) Non-IFRS measure. See pages M40 to M50 for details.
(2) For details of the adjustments to revenues, included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of the MD&A.
(3) Gross installed capacity.
(4) In accordance with IFRS.

Where We Are Going

We believe the current decade will be one of massive clean energy expansion and we are excited about the role that TransAlta will play. We have a proven track record along with the expertise and experience to meet the challenge.

Clean Electricity Growth Plan Execution

2021 → 2025

Renewables Growth

40% — 2GW

2021 — 2025 goal

Growth Capital

41% — $3.6B

2021 — 2025 goal

Incremental EBITDA

47% — $315M

2021 — 2025 goal

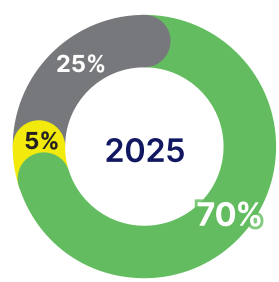
Development Pipeline

60% — 5GW

2021 — 2025 goal

374 MW
in Advanced-Stage Development

Targeted Adjusted EBITDA



- Renewables
- Energy Marketing
- Natural Gas

2025 → 2030

5GW
of Growth Pipeline

2X
increase in Renewables Fleet

How We Are Doing It

Our mission is to provide safe, low-cost and reliable clean electricity to our customers. As a customer-centred clean energy leader, we are well positioned to support our customers' ESG and sustainability goals. To achieve this goal in today's evolving economy and increasingly electrified world, our strategy focuses on renewable electricity growth and a deep commitment to sustainability. We believe we are uniquely positioned as the world continues to electrify and adopt sustainability practices.

Sustainability Targets

Achieving Results

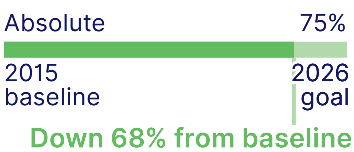
Our 2023 and longer-term sustainability targets support the long term success of our business so that the Company will continue to be positioned as an ESG leader in the future. Goals and targets are established to improve our ESG performance and to manage current and emerging material sustainability issues.

Nine UN SDGs we support:

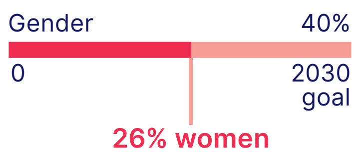
2022 ESG Highlights

Performance against a selection of 2022 sustainability targets is highlighted below:

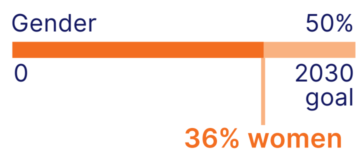
Environment
GHG emissions reduction



Social
Workforce diversity



Governance
Board diversity

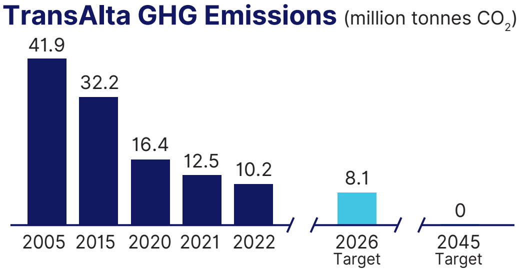


Clean Energy Transition

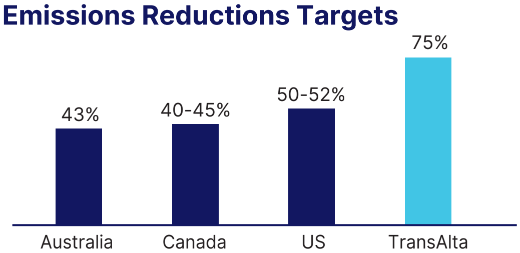
Delivering on Our Plan

We are a clean electricity leader with a focus on tangible greenhouse gas emissions reductions. We have adopted a net-zero by 2045 target, and an ambitious CO_2 emissions reduction target of 75% by 2026 from 2015 levels. We also plan to deliver 2 GW of new renewables capacity by deploying $3.6 billion of growth capital by the end of 2025.

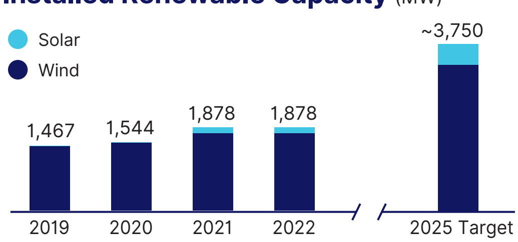
TransAlta GHG Emissions (million tonnes CO_2)



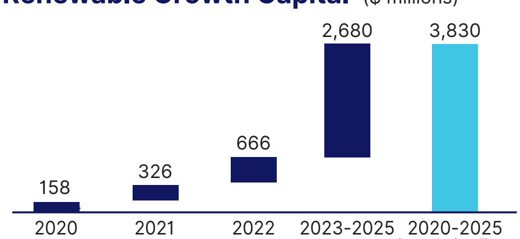
Emissions Reductions Targets



Installed Renewable Capacity (MW)



Renewable Growth Capital[1] ($ millions)



(1) See page M95 of the MD&A for details

Management's Discussion and Analysis

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with our 2022 audited annual consolidated financial statements (the "consolidated financial statements") and our 2022 annual information form ("AIF"), each for the fiscal year ended Dec. 31, 2022. 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, 2022. 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 February 22, 2023. Additional information respecting TransAlta Corporation ("TransAlta", "we", "our", "us" or the "Company"), including our AIF, is available on SEDAR at www.sedar.com, on EDGAR at www.sec.gov and on our website at www.transalta.com. Information on or connected to our website is not incorporated by reference herein.

Forward-Looking Statements

This MD&A includes "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable United States ("US") securities laws, including the United States Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). All forward-looking statements are based on our beliefs as well as assumptions based on information available at the time the assumptions were made and on management's experience and perception of historical trends, current conditions and expected future developments, as well as other factors deemed appropriate in the circumstances. Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may," "will," "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, statements relating to: our Clean Electricity Growth Plan and ability to achieve the target of 2 gigawatts ("GW") of incremental renewables capacity with an estimated capital investment of $3.6 billion that is expected to deliver incremental average annual EBITDA of $315 million; the Company's projects under construction, including the timing of commercial operations, expected annual EBITDA and associated costs, including the Horizon Hill wind project, the White Rock wind projects, Northern Goldfields solar project, Garden Plain wind project and the Mount Keith 132kV transmission expansion; the Montem pumped hydro development project and related renewable projects; the execution of the Company's early, and advanced-stage development pipeline, including the size, cost and expected EBITDA from such projects; the expansion of the Company's early stage development pipeline to 5 GW; the proportion of EBITDA to be generated from renewable sources by the end of 2025; the 2023 Financial Outlook (defined below), including adjusted EBITDA, free cash flow and annualized dividend per share; the Company's ability to enhance shareholder value through its NCIB (as defined below); the reduction of carbon emissions by 75 per cent from 2015 emissions levels by 2026; the remediation of the Kent Hills 1 and 2 wind facilities, including, the timing and cost of such remediation, the resulting impact of such rehabilitation on the Company's revenues and the potential battery storage project at and repowering of, the Kent Hills facilities; the expected impact and quantum of carbon compliance costs; regulatory developments and their expected impact on the Company, including the Canadian federal climate plan and the implementation of the major aspects thereof (including increased carbon pricing and increased funding for clean technology), the proposed new Clean Electricity Regulations, the Clean Fuel Regulations and Canadian Greenhouse Gas Offset Credit System Regulations and the ability of the Company to realize benefits from Canadian, United States and Australian regulatory developments, including receiving funding or favourable tax treatment for clean electricity projects; the potential value of emission reduction credits; modelling and scenario analysis associated with climate change management and the resiliency of the Company's strategy under various climate scenarios; sustaining and productivity capital in 2023; expected power prices in Alberta, Ontario and the Pacific Northwest; AECO gas prices; the cyclicality of the business, including as it relates to maintenance costs, production and loads; expectations regarding refinancing debt maturing from 2023 and 2025; and the Company continuing to maintain a strong financial position and significant liquidity without any significant impact from the current economic environment.

The forward-looking statements contained in this MD&A are based on many assumptions including, but not limited to, the following: no significant changes to applicable laws and regulations beyond those that have already been announced; no significant changes to fuel and purchased power costs; no material adverse impacts to long-term investment and credit markets; no significant changes to power price and hedging assumptions, including Alberta spot prices of $105/MWh to $135/MWh in 2023, Mid-Columbia spot prices of US$75/MWh to US$85/MWh in 2023, and AECO gas prices of $4.60/GJ in 2023; hedged volumes and prices in 2023; sustaining capital of $140 million to $170 million in 2023; Energy Marketing gross margin of $90 million to $110 million in 2023; no significant changes to gas commodity prices and transport costs; no significant changes to the decommissioning and restoration costs of the retired Alberta assets; no significant changes to interest rates; no significant changes to the demand and growth of renewables generation; no significant changes to the Company's debt and credit ratings; the Company's proportionate ownership of TransAlta Renewables Inc. ("TransAlta Renewables") not changing materially; and no decline in the dividends to be received from TransAlta Renewables.

Forward-looking statements are subject to a number of significant risks and uncertainties 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 risks relating to: force majeure claims; 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; our ability to obtain regulatory and any other third-party approvals on the expected timelines or at all in respect of our growth projects; risks associated with development and construction projects, including as it pertains to increased capital costs, permitting, labour and engineering risks, disputes with contractors and potential delays in the construction or commissioning of such projects; restricted access to capital and increased borrowing costs; significant fluctuations in the Canadian dollar against the US dollar and Australian dollar; changes in short-term and long-term electricity supply and demand; fluctuations in market prices, including lower merchant pricing in Alberta, Ontario and Mid-Columbia; reductions in production; a higher rate of losses on our accounts receivable; inability to achieve our targets relating to ESG (as defined below); impairments and/or write-downs of assets; adverse impacts on our information technology systems and our internal control systems, including increased cybersecurity threats; commodity risk management and energy trading risks, including the effectiveness of the Company’s risk management tools associated with hedging and trading procedures to protect against significant losses; 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; disruptions in the transmission and distribution of electricity; the effects of weather, including man-made or natural disasters and other climate-change related risks; increases in costs; inability to satisfy the conditions to closing of the acquisition of an interest in the Tent Mountain pumped hydro development project; reductions to our generating units’ relative efficiency or capacity factors; disruptions in the source of fuels, including natural gas, coal, water, solar or wind resources required to operate our facilities; operational risks, unplanned outages and equipment failure and our ability to carry out or have completed any repairs in a cost-effective or timely manner or at all, including as it applies to the remediation and replacement of turbine foundations of the Kent Hills 1 and 2 wind facilities; general economic risks, including deterioration of equity markets, increasing interest rates or rising inflation; failure to meet financial expectations; general domestic and international economic and political developments; armed hostilities, including the war in Ukraine and associated impacts; the threat of terrorism; adverse diplomatic developments or other similar events that could adversely affect our business; industry risk and competition; fluctuations in the value of foreign currencies; structural subordination of securities; counterparty credit risk; public health crisis risks, including any further impacts of COVID-19; changes to our relationship with, or ownership of, TransAlta Renewables; changes in the payment or receipt of future dividends, including from TransAlta Renewables; inadequacy or unavailability of insurance coverage; our provision for income taxes and any risk of reassessment; legal, regulatory and contractual disputes and proceedings involving the Company; 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 our 2022 Annual MD&A and the Risk Factors section in our AIF for the year ended Dec. 31, 2022.

Readers are urged to consider these factors carefully in evaluating the forward-looking statements, which reflect the Company's expectations only as of the date hereof and are cautioned not to place undue reliance on them. 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.

Description of the Business

Portfolio of Assets

TransAlta is a Canadian corporation and one of Canada's largest publicly traded power generators with over 111 years of operating experience. We own, operate and manage a geographically diversified portfolio of assets utilizing a broad range of input resources that includes water, wind, solar, natural gas and thermal coal. We are one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.

Our Clean Electricity Growth Plan, announced in 2021, will continue to advance our leadership position in renewable electricity. In 2022, our renewable energy gross installed capacity is 2,828 MW and we have over 600 MW of renewable energy under construction.

TransAlta is actively transitioning our business to manage climate change risks and opportunities and has demonstrated leadership through action on climate-change related issues. The Company no longer generates electricity in Canada using coal. We have retired 4,464 MW of coal-fired generation capacity and converted 1,659 MW of coal-fired facilities to natural gas since 2018. Our remaining coal-fired unit in Washington State is scheduled to retire at the end of 2025.

We are on track to achieve our target of reducing our greenhouse gas ("GHG") emissions by 75 per cent from 2015 levels by 2026. Since 2015, we have reduced GHG emissions by 22 million tonnes of CO_2e or 68 per cent.

The following table provides our consolidated ownership of our facilities across the regions in which we operate as of Dec. 31, 2022:

As at Dec. 31, 2022		Hydro	Wind and Solar	Gas	Energy Transition	Total
Alberta	Gross installed capacity (MW)(1)	834	636	1,960	—	3,430
	Number of facilities	17	13	7	—	37
	Weighted average contract life (years)(2)(3)(4)	—	6	1	—	2
Canada, Excluding Alberta	Gross installed capacity (MW)(1)	88	751	645	—	1,484
	Number of facilities	7	9	3	—	19
	Weighted average contract life (years)(3)	6	11	9	—	10
US	Gross installed capacity (MW)(1)	—	519	29	671	1,219
	Number of facilities	—	7	1	2	10
	Weighted average contract life (years)(3)	—	11	3	3	7
Australia	Gross installed capacity (MW)(1)	—	—	450	—	450
	Number of facilities	—	—	6	—	6
	Weighted average contract life (years)(3)	—	—	16	—	16
Total	**Gross installed capacity (MW)(1)**	**922**	**1,906**	**3,084**	**671**	**6,583**
	Number of facilities	**24**	**29**	**17**	**2**	**72**
	Weighted average contract life (years)(3)	**1**	**10**	**5**	**3**	**6**

(1) Gross installed capacity for consolidated reporting represents 100 per cent output of a facility. Capacity figures for the Wind and Solar segment includes 100 per cent of the Kent Hills wind facilities; Gas includes 50 per cent of the Ottawa and Windsor facilities, 100 per cent of the Poplar Creek facility, 50 per cent of the Sheerness facility and 60 per cent of the Fort Saskatchewan facility.

(2) The weighted average contract life for Hydro and certain gas and wind assets in Alberta are nil as they are operating primarily on a merchant basis in the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for more information.

(3) For power generated under long-term power purchase agreements ("PPA"), power hedge contracts and short-term and long-term industrial contracts, the PPAs have a weighted average remaining contract life based on long-term average gross installed capacity.

(4) The weighted average remaining contract life is related to the contract period for McBride Lake (38 MW), Windrise Wind (206 MW), Poplar Creek (115 MW) and Fort Saskatchewan (71 MW), with the remaining wind and gas facilities operated on a merchant basis in the Alberta market.

Highlights

Consolidated Financial Highlights

Year ended Dec. 31	2022	2021	2020
Adjusted availability (%)	**90.0**	86.6	90.7
Production (GWh)	**21,258**	22,105	24,980
Revenues	**2,976**	2,721	2,101
Fuel and purchased power	**1,263**	1,054	805
Carbon compliance	**78**	178	163
Operations, maintenance and administration	**521**	511	472
Adjusted EBITDA[(1)(2)]	**1,634**	1,286	917
Earnings (loss) before income taxes	**353**	(380)	(303)
Net earnings (loss) attributable to common shareholders	**4**	(576)	(336)
Cash flow from operating activities	**877**	1,001	702
Funds from operations[(1)(2)]	**1,346**	994	675
Free cash flow[(1)(2)]	**961**	585	348
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.01**	(2.13)	(1.22)
Dividends declared per common share[(3)]	**0.21**	0.19	0.22
Dividends declared per preferred share[(3)]	**1.20**	1.02	1.27
Funds from operations per share[(1)(4)]	**4.97**	3.67	2.45
Free cash flow per share[(1)(4)]	**3.55**	2.16	1.27

As at Dec. 31	2022	2021	2020
Total assets	**10,741**	9,226	9,747
Total consolidated net debt[(1)(5)]	**2,854**	2,636	2,974
Total long-term liabilities	**5,864**	4,702	5,376
Total liabilities	**8,752**	6,633	6,311

(1) These items are not defined and have no standardized meaning under IFRS. Presenting these items from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(2) During 2022, our adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Therefore, the Company has applied this composition to all previously reported periods.

(3) Weighted average of the Series A, B, C, D, E and G preferred share dividends declared. Dividends declared vary period over period due to the timing of dividend declarations and quarterly floating rates.

(4) Funds from operations ("FFO") per share and free cash flow ("FCF") per share are calculated using the weighted average number of common shares outstanding during the period. The weighted average number of common shares outstanding for the year ended Dec. 31, 2022, was 271 million shares (2021 – 271 million, 2020 – 275 million). Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

(5) Total consolidated net debt includes long-term debt, including the 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. Refer to the table in the Financial Capital section of this MD&A for more details on the composition of total consolidated net debt.

The Company exceeded the top end of its adjusted EBITDA and FCF guidance during the year with exceptional performance in all of our generation segments as well as our Energy Marketing segment. The Hydro and Gas facilities in the Alberta Electricity Portfolio were well positioned to capture opportunities from the strong spot market conditions. Wind and Solar benefited from a full year of operations from the Windrise wind and North Carolina Solar facilities. The Energy Transition segment had strong performance from Centralia Unit 2, which was offset by the reductions related to the retirement of Keephills Unit 1 and Sundance Unit 4.

Adjusted availability for 2022 was 90.0 per cent compared to 86.6 per cent in 2021. The increase was primarily due to lower planned outages within the Gas segment with the completion of the coal-to-gas conversions in 2021, higher reliability of the coal-to-gas converted units compared to coal units and lower planned and unplanned outages at our Alberta Hydro Assets and Centralia Unit 2, partially offset by the extended outage at the Kent Hills 1 and 2 wind facilities.

Production for 2022 was 21,258 gigawatt hours ("GWh") compared to 22,105 GWh in 2021. Overall, the decrease in production was primarily due to the retirement of Keephills Unit 1 and Sundance Unit 4 and the extended outage at the Kent Hills 1 and 2 wind facilities. This was partially offset by an increase in production from the Gas segment due to higher availability and dispatch optimization of the Alberta assets; higher production at the Ada cogeneration facility; the addition of the Windrise wind facility commissioned in the fourth quarter of 2021, the North Carolina Solar facility acquired in the fourth quarter of 2021 and higher wind resources in Eastern Canada, all in our Wind and Solar segment; and an increase in production from Centralia Unit 2 in 2022 in our Energy Transition segment.

Revenues for 2022 increased by $255 million compared to 2021, mainly as a result of capturing higher realized energy prices within the Alberta electricity market through our optimization and operating activities, and higher realized ancillary services prices and volumes in the Hydro segment. Revenues net of realized and unrealized losses from hedging and derivative positions also increased due to higher merchant prices and volumes at Centralia. The Wind and Solar segment benefited from increased production and an increase in emission credit sales over the prior year.

Fuel and purchased power costs in 2022 increased by $209 million compared to 2021. The Gas and Energy Transition segments experienced higher natural gas pricing and there was increased natural gas consumption from our recently converted units. This was partially offset by our hedged positions on gas, lower coal costs and no mine depreciation due to the termination of all coal-mining activities in Canada as of Dec. 31, 2021.

Carbon compliance costs in 2022 decreased by $100 million compared to 2021, primarily due to reductions in GHG emissions and utilization of our compliance credits to settle a portion of the GHG obligation, partially offset by an increase in the carbon price per tonne and higher production in the Gas segment. Lower GHG emissions were a direct result of operating exclusively on natural gas in Alberta rather than coal, resulting in changes in the Company's fuel mix ratio.

Operations, maintenance and administration ("OM&A") expenses for 2022 increased by $10 million compared to 2021. Excluding the impact of the Canada Emergency Wage Subsidy ("CEWS") funding received in 2021, OM&A expenses were higher mainly due to the Company's performance-related incentive accruals, OM&A related to the addition of the Windrise wind and North Carolina Solar facilities and higher general operating expenses. In 2021, OM&A included $28 million related to a write-down on parts and material inventory related to the Highvale mine and coal operations.

Adjusted EBITDA increased by $348 million compared to 2021, largely due to strong performance from our Alberta Electricity Portfolio, driven primarily by the hydro, gas and wind facilities as a result of higher merchant prices and dispatch optimization. Adjusted EBITDA was further improved by incremental production from new facilities, higher ancillary service revenues, liquidated damages recoverable due to turbine availability being below the contractual target at the Windrise wind facility, higher environmental attribute revenues in the Wind and Solar segment and lower carbon compliance costs in both the Gas and Energy Transition segments. This was partially offset by lower adjusted EBITDA from the retirement of Alberta coal units in the Energy Transition segment, higher natural gas fuel costs, lower production from the extended outage at the Kent Hills wind facilities, higher OM&A expenses related to the Company's performance-related incentive accruals and increased general operating expenses. Changes in segmented adjusted EBITDA are discussed in the Segmented Financial Performance and Operating Results section of this MD&A.

Earnings before income taxes for 2022 increased by $733 million compared to 2021. **Net earnings attributable to common shareholders** for 2022 were $4 million compared to a loss of $576 million in 2021. In 2022, the Company benefited from higher revenues net of realized and unrealized losses from hedging and derivative positions and lower carbon compliance costs, partially offset by higher fuel and purchased power, higher depreciation due to the acceleration of useful lives on certain facilities, higher interest expense due to increased costs to support trading and hedging activities and higher accretion of provisions, partially offset by higher interest income and higher income tax expense due to higher earnings before tax and current and prior period tax adjustments in the US to mitigate cash tax. In addition, during 2022, the Company recognized liquidated damages recoverable due to turbine availability being below the contractual target at the Windrise wind facility. Net earnings attributable to common shareholders in 2021 were significantly impacted by higher asset impairment charges resulting from the Company's decisions to shut down the Highvale mine, suspend the Sundance Unit 5 repowering project and retire Sundance Unit 4 and Keephills Unit 1.

Cash flow from operating activities decreased by $124 million compared with 2021, primarily due to unfavourable changes in working capital and higher fuel and purchased power costs. This was partially offset by higher revenues from risk management activities, higher net other operating (income) loss and lower carbon compliance costs.

FCF, one of the Company's key financial metrics, totalled $961 million compared to $585 million in 2021. This represents an increase of $376 million, driven primarily by higher adjusted EBITDA, favourable changes in provisions from 2021 and a decrease in sustaining capital spending related to fewer planned maintenance turnarounds. This was partially offset by higher current income tax expense, higher distributions paid to subsidiaries' non-controlling interests and higher decommissioning and restoration costs settled.

Ability to Deliver Financial Results

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

Year ended Dec. 31		2022	2021	2020
	Original Target	**1,065-1,185**	960-1,080	925-1,000
Adjusted EBITDA (1)	Revised Target(2)	**1,380-1,460**	1,200-1,300	n/a
	Actual(3)	**1,634**	1,286	917
	Original Target	**455-555**	340-440	325-375
FCF (1)	Revised Target(2)	**725-775**	500-560	n/a
	Actual(3)	**961**	585	348

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(2) In November 2022, as a result of the strong performance in the third quarter, the Company revised the outlook targets for adjusted EBITDA and FCF from the previously announced target range. In 2021, the Company revised adjusted EBITDA and FCF as a result of strong performance in the second and third quarters of 2021.
(3) The 2021 and 2020 actual adjusted EBITDA and FCF were revised during the second quarter of 2022 to be consistent with the currently defined composition of adjusted EBITDA and FCF. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further information.

Sustaining Capital

We are in a long-cycle, capital-intensive business that requires significant capital expenditures. Our goal is to undertake sustaining capital expenditures that ensure our facilities operate reliably and safely.

Year ended Dec. 31	2022	2021	2020
Total sustaining capital expenditures	**142**	199	157

Total sustaining capital expenditures were $57 million lower compared to 2021, mainly due to lower planned major maintenance turnarounds for the gas fleet as a result of coal-to-gas conversions being completed in 2021, partially offset by higher planned maintenance expenditures across the wind and hydro facilities, and additional expenditures on leasehold improvements within the Corporate segment.

Significant and Subsequent Events

Early-Stage Pumped Hydro Development Project

On Feb. 16, 2023, the Company announced that it had entered into a definitive agreement to acquire a 50 per cent interest in the Tent Mountain Renewable Energy Complex ("Tent Mountain"), an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, currently owned by Montem Resources Limited ("Montem"). The acquisition includes the land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company will pay Montem approximately $8 million upon closing the transaction with additional contingent payments of up to $17 million (approximately $25 million total) based on the achievement of specific development and commercial milestones. The Company and Montem will form a partnership and jointly manage the project, with the Company acting as project developer. The partnership will actively seek an offtake agreement over the development period for the energy and environmental attributes generated by the facility. The acquisition also includes the intellectual property associated with a 100 MW offsite green hydrogen electrolyser and a 100 MW offsite wind development project. The closing of the transaction remains subject to customary closing conditions, including receipt of shareholder approval by Montem which is expected to occur in March 2023.

TransAlta and Lafarge Canada Advance Low-Carbon Fly Ash Repurposing Project

During the fourth quarter of 2022, the Company entered into an agreement with Lafarge Canada that will advance low-carbon concrete projects in Alberta. The project will repurpose landfilled fly ash, a waste product from the Company's Canadian coal-fired electricity facilities, which ceased operating on coal at the end of 2021. The ash will be used to replace cement in concrete manufacturing.

Changes to the Board of Directors

On Dec. 15, 2022, the Company announced the appointment of Ms. Manjit Sharma to the Board of Directors (the "Board" or the "Board of Directors") effective Jan. 1, 2023. Ms. Sharma brings over 30 years of experience that spans a variety of industries, most recently serving as Chief Financial Officer of WSP Canada Inc.

On Sept. 30, 2022, Ms. Beverlee Park retired from the Board of Directors. Ms. Park served on the Board of Directors since 2015 and as Chair of the Audit, Finance and Risk Committee from April 2018 to May 2022. The Company recognizes the many contributions made by Ms. Park to TransAlta, and thanks her for the many years of service.

Public Offering of US$ Senior Green Bonds and Release of Inaugural Green Bond Framework

On Nov. 17, 2022, the Company issued US$400 million senior notes ("US$400 million Senior Green Bonds"), which have a coupon rate of 7.75 per cent per annum and mature on Nov. 15, 2029. Including the effects of settled interest rate swaps, the notes have an effective yield of approximately 5.98 per cent. The notes are an unsecured obligation, rank equally in right of payment with all of our existing and future senior indebtedness, and are senior in right of payment to all of our future subordinated indebtedness. The interest payments on the bonds are made semi-annually, on November 15 and May 15, with the first payment commencing May 15, 2023.

The Company used the net proceeds from the issuance of the notes to repay $100 million drawn on its credit facility and replaced the balance sheet cash used to fund the repayment in full of the Company's US$400 million 4.50 per cent unsecured senior notes.

The Company will allocate an amount equal to the net proceeds from this offering to finance or refinance new and/or existing eligible green projects in accordance with its Green Bond Framework (the "Framework"). The Framework received a second-party opinion from Sustainalytics, which verified that it aligned with the Green Bond Principles from the International Capital Market Association.

Announced a 10 per cent Common Share Dividend Increase

On Nov. 7, 2022, the Company announced that the Board of Directors approved a 10 per cent increase in its common share dividend and declared a dividend of $0.055 per common share that was paid on Jan. 1, 2023. The quarterly dividend of $0.055 per common share represents an annualized dividend of $0.22 per common share.

New Term Facility

During the third quarter of 2022, the Company closed a two-year $400 million floating-rate term facility ("Term Facility") with its banking syndicate with a maturity date of Sept. 7, 2024. As at Dec. 31, 2022, the full amount was drawn on the Term Facility.

Conversion Results for Series E and F Preferred Shares

On Sept. 21, 2022, there were 89,945 Cumulative Redeemable Rate Reset First Preferred Shares, Series E (“Series E Shares”) tendered for conversion, which was less than the one million shares required to give effect to conversions into Cumulative Redeemable Rate Reset First Preferred Shares, Series F (“Series F Shares”). As a result, no Series E Shares were converted into Series F Shares.

Executed Contract Renewals with the IESO at Sarnia Cogeneration and Melancthon 1 Wind Facilities

During the third quarter of 2022, TransAlta Renewables Inc., a subsidiary of the Company, announced that it was awarded capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility from the Ontario Independent Electricity System Operator (“IESO”) as part of the IESO’s Medium-Term Capacity Procurement Request for Proposals. The new capacity contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility run from May 1, 2026, to April 30, 2031. It is intended that the existing contracts for the Sarnia cogeneration facility and the Melancthon 1 wind facility will be extended from Dec. 31, 2025 and March 3, 2026, respectively, to April 30, 2026. The Company expects the gross margin from the Sarnia cogeneration facility to be reduced by approximately 30 per cent as a result of the IESO price cap under the new contract.

Executed Industrial Contract Extensions at Sarnia Cogeneration

During the second and fourth quarters of 2022, the Company executed contracts for the supply of electricity and steam from the Sarnia cogeneration facility with three of its legacy industrial customers, and with three of its new customers, who had previously been re-sold utilities as part of a legacy customer's contract. Following the contracting efforts in 2021 and 2022, the Sarnia cogeneration facility has been fully re-contracted without interruption to the customers' delivery terms. The contracts extend to April 30, 2031, for four customers and to Dec. 31, 2032 for the other three customers.

TransAlta Debuts New Brand Reiterating Commitment to a Clean Energy Future

On June 20, 2022, the Company announced and launched a new brand, including company logo and tagline, "Energizing the Future". The new visual identity encapsulates the TransAlta of today while reinforcing the Company’s focus as a leader in creating a net-zero future.

Conversion Results for Series C and D Preferred Shares

On June 30, 2022, the Company converted 1,044,299 of its 11,000,000 Cumulative Redeemable Rate Reset First Preferred Shares, Series C (“Series C Shares”), on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D (“Series D Shares”).

Court of Appeal Upholds TransAlta’s Favourable Force Majeure Arbitration Decision

On June 9, 2022, the Alberta Court of Appeal released a unanimous decision dismissing ENMAX Energy Corporation ("ENMAX") and the Balancing Pool's applications to set aside an arbitration decision in favour of the Company. The Court of Appeal upheld the Company’s claim of force majeure that arose when its Keephills Unit 1 generating unit was forced offline in 2013. As a result of the decision, the Company’s claim of force majeure remains valid, and the associated costs of the force majeure event will not be reassessed against TransAlta.

Keephills Unit 2 Stator Force Majeure Dispute Settled

After the Keephills Unit 1 stator force majeure outage in 2013, it was determined that Keephills Unit 2 could face a similar stator failure before the next planned outage. In response, the Company took Keephills Unit 2 offline between January 31, 2014, and March 15, 2014 to perform a full rewind of the generator stator and claimed force majeure. The Balancing Pool disputed this force majeure event but the dispute was held in abeyance pending the outcome of the Keephills Unit 1 stator force majeure dispute, which was recently concluded. The Company and the Balancing Pool recently settled this dispute, resulting in the resolution of both stator force majeure claims.

Kent Hills Wind Facilities Update

On June 2, 2022, TransAlta Renewables announced the rehabilitation plan for the Kent Hills 1 and 2 wind facilities. In addition to the announcement, TransAlta Renewables amended and extended PPAs with New Brunswick Power Corporation ("NB Power") in respect of each of the Kent Hills 1, 2 and 3 wind facilities, providing for an additional 10-year contract term to December 2045 and an effective 10 per cent reduction to the original contract prices from January 2023 through December 2033. In addition, both parties have agreed to work in good faith to evaluate the installation of a battery energy storage system at Kent Hills and to consider a potential repowering of Kent Hills at the end of life in 2045. A waiver for the Kent Hills wind non-recourse bonds ("KH Bonds") was also obtained from the project bondholders and a supplemental indenture was entered into with the bondholders that facilitates the rehabilitation of the Kent Hills 1 and 2 wind facilities. Refer to the Wind and Solar segment discussion in the Segmented Financial Performance and Operating Results section and Financial Capital section of this MD&A for further details.

TSX Acceptance of Normal Course Issuer Bid

On May 24, 2022, the Toronto Stock Exchange (“TSX”) accepted the notice filed by the Company to renew its normal course issuer bid (“NCIB”) for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14,000,000 common shares, representing approximately 7.16 per cent of its public float of common shares as at May 17, 2022. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2022, and ends on May 30, 2023, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Company’s election.

The NCIB provides the Company with a capital allocation alternative with a view to ensuring long-term shareholder value. TransAlta’s Board of Directors and management believe that, from time to time, the market price of the common shares does not reflect their underlying value and purchases of common shares for cancellation under the NCIB may provide an opportunity to enhance shareholder value.

During the year ended Dec. 31, 2022, the Company purchased and cancelled a total of 4,342,300 common shares at an average price of $12.48 per common share, for a total cost of $54 million.

Mount Keith 132kV Transmission Expansion

On May 3, 2022, TransAlta Renewables exercised its option to acquire an economic interest in the expansion of the Mount Keith 132kV transmission system in Western Australia that will support the Northern Goldfields-based operations of BHP Nickel West ("BHP"). The project is being developed under the existing PPA with BHP, which has a term of 15 years. It is expected to be completed in the second half of 2023. The project will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase its competitiveness as a supplier of low-carbon nickel.

Executed Long-term PPA for the Remaining 30 MW at Garden Plain

During the second quarter of 2022, the Company entered into a long-term PPA for the remaining 30 MW of renewable electricity and environmental attributes for the Garden Plain wind project in Alberta with a new investment-grade globally recognized customer. The 130 MW Garden Plain wind project, which was announced in May 2021 with a 100 MW PPA contracted to Pembina Pipeline Corporation ("Pembina"), is now fully contracted with a weighted average contract life of approximately 17 years. Construction is underway with commercial operation expected in the first half of 2023.

Energy Impact Partners Investment

On May 5, 2022, the Company entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners ("EIP") Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). During 2022, the Company invested $10 million (US$8 million). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions.

Customer Update at White Rock Wind Projects

During the second quarter of 2022, TransAlta identified Amazon Energy LLC ("Amazon") as the customer for the 300 MW White Rock wind projects, to be located in Caddo County, Oklahoma. On Dec. 22, 2021, Amazon and TransAlta entered into two long-term PPAs for the supply of 100 per cent of the renewable electricity and environmental attributes from the projects. Construction activities started in the fall of 2022 with a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facilities.

MSCI Environmental, Social and Governance Rating Upgrade

During the second quarter of 2022, TransAlta's MSCI Environmental, Social and Governance ("ESG") Rating was upgraded to 'A' from 'BBB'. The upgrade reflects the Company's strong renewable energy growth compared to peers. In 2021, the Company grew its installed renewable energy capacity by 15 per cent through the acquisition and construction of solar and wind facilities and secured 600 MW in additional renewable energy projects. In line with its goal to reduce carbon emissions by 75 per cent from 2015 emissions levels by 2026, TransAlta also completed coal-to-gas conversions of its Canadian coal-fired facilities in 2021, nine years ahead of Alberta's coal phase-out plan.

Horizon Hill Wind Project and Fully Executed Corporate PPA with Meta

On April 5, 2022, TransAlta announced a long-term renewable energy PPA with a subsidiary of Meta Platforms Inc. ("Meta"), formerly known as Facebook, Inc., for 100 per cent of the generation from its 200 MW Horizon Hill wind project to be located in Logan County, Oklahoma. Under this agreement, Meta will receive both renewable electricity and environmental attributes from the Horizon Hill facility. The facility will consist of a total of 34 Vestas turbines. Construction commenced in the fall of 2022 with a target commercial operation date in the second half of 2023. TransAlta will construct, operate and own the facility.

Segmented Financial Performance and Operating Results

Segmented information is prepared on the same basis that the Company manages its business, evaluates financial results and makes key operating decisions.

Consolidated Results

The following table reflects the generation and summary financial information on a consolidated basis for the year ended Dec. 31:

	LTA generation (GWh)[(1)]			Actual production (GWh)[(2)]			Adjusted EBITDA[(3)]		
Year ended Dec. 31	**2022**	**2021**	**2020**	**2022**	**2021**	**2020**	**2022**	**2021[(4)]**	**2020[(4)]**
Hydro	**2,015**	2,030	2,030	**1,988**	1,936	2,132	**527**	322	105
Wind and Solar	**4,950**	4,345	3,916	**4,248**	3,898	4,069	**311**	262	248
Renewables	**6,965**	6,375	5,946	**6,236**	5,834	6,201	**838**	584	353
Gas				**11,448**	10,565	10,780	**629**	488	367
Energy Transition				**3,574**	5,706	7,999	**86**	133	175
Energy Marketing							**183**	166	103
Corporate							**(102)**	(85)	(81)
Total				**21,258**	22,105	24,980	**1,634**	1,286	917
Earnings (loss) before income taxes							**353**	(380)	(303)

(1) Long-term average production ("LTA Generation (GWh)") is calculated based on our portfolio as at Dec. 31, 2022, on an annualized basis from the average annual energy yield predicted from our simulation model based on historical resource data performed over a period of typically 30-35 years for the Wind and Solar segments and 36 years for Hydro segment. LTA Generation (GWh) for Energy Transition is not considered as we are currently transitioning these units completely by the end of 2025 and the LTA Generation (GWh) for Gas is not considered as it is largely dependent on market conditions and merchant demand. LTA Generation (GWh) for the year ended Dec. 31, 2022, excluding the Kent Hills 1 and 2 wind facilities which are currently not in operation, is approximately 4,563 GWh.

(2) Actual production levels are compared against the long-term average to highlight the impact of an important factor that affects the variability in our business results. In the short-term, for each of the Hydro and Wind and Solar segments, the conditions will vary from one period to the next and over time facilities will continue to produce in line with their long-term averages, which have proven to be reliable indicators of performance.

(3) This item is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

(4) Adjustments to the Gas and Energy Marketing segment were made for the impact of realized gains and losses on closed exchange positions. Refer to the Additional IFRS Measures and Non-IFRS Measures section under the Reconciliation of Non-IFRS Measures section of this MD&A.

Hydro

Year ended Dec. 31	2022	2021	2020
Gross installed capacity (MW)[1]	**922**	925	925
LTA (GWh)	**2,015**	2,030	2,030
Availability (%)	**96.7**	92.4	93.2
Production			
Contract production (GWh)	**323**	434	2,056
Merchant production (GWh)	**1,665**	1,502	76
Total energy production (GWh)	**1,988**	1,936	2,132
Ancillary service volumes (GWh)[2]	**3,124**	2,897	2,857
Alberta Hydro Assets revenues[3]	**328**	185	87
Other Hydro Assets and other revenues[3][4]	**42**	41	45
Alberta Hydro ancillary services revenues[2]	**236**	160	66
Capacity payments[5]	**—**	—	60
Environmental attribute revenues	**1**	1	—
Total gross revenues	**607**	387	258
Net payment relating to Alberta Hydro PPA[6]	**—**	(4)	(106)
Revenues[7]	**607**	383	152
Fuel and purchased power	**22**	16	8
Gross margin[7]	**585**	367	144
OM&A	**55**	42	37
Taxes, other than income taxes	**3**	3	2
Adjusted EBITDA[7]	**527**	322	105
Supplemental Information:			
Gross revenues per MWh			
Alberta Hydro Assets energy ($/MWh)	**197**	123	51
Alberta Hydro Assets ancillary ($/MWh)	**76**	55	23
Sustaining capital	**35**	26	20

(1) In the fourth quarter of 2022, the Company closed the sale of two Hydro assets resulting in a reduction in capacity of 3 MW.
(2) Ancillary services as described in the AESO Consolidated Authoritative Document Glossary.
(3) Alberta Hydro Assets include 13 hydro facilities on the Bow and North Saskatchewan river systems. Other Hydro assets includes our hydro facilities in BC and Ontario, hydro facilities in Alberta (other than the Alberta Hydro Assets) and transmission revenues.
(4) Other revenue includes revenues from our transmission business and other contractual arrangements, including the flood mitigation agreement with the Government of Alberta and black start services.
(5) Capacity payments include the annual capacity charge as described in the Power Purchase Arrangements Determination Regulation AR 175/2000, available from Alberta King's Printer. The PPA expired on Dec. 31, 2020.
(6) The net payment relating to the Alberta Hydro PPA represents the Company's financial obligations for notional amounts of energy and ancillary services in accordance with the Alberta Hydro PPA that expired on Dec. 31, 2020. The amount in 2021 related to adjustments for the final payment under the Alberta PPA.
(7) This item is not defined and has no standardized meaning under IFRS. For details of the adjustments to revenues and net other operating income included in adjusted EBITDA refer to the Additional IFRS and Non-IFRS Measures section of this MD&A.

2022

Availability for 2022 increased compared to 2021, primarily due to lower planned and unplanned outages at our Alberta Hydro Assets.

Production for 2022 increased by 52 GWh compared to 2021, mainly due to higher availability.

Ancillary services volumes for 2022 increased by 227 GWh compared to 2021, due to higher availability and demand.

Adjusted EBITDA for 2022 increased by $205 million compared to 2021, primarily due to higher merchant prices, higher production and higher ancillary service prices and volumes in the Alberta market. This was partially offset by higher OM&A costs for the year related to increased insurance premiums for updated replacement value coverage and the Company's performance-related incentive accruals. For further discussion on the Alberta market conditions and pricing, refer to the Alberta Electricity Portfolio section of this MD&A.

Sustaining capital expenditures for 2022 were $9 million higher compared to 2021, due to higher planned maintenance in 2022.

2021

Availability for 2021 decreased compared to 2020, primarily due to higher planned and unplanned outages.

Production for 2021 decreased by 196 GWh compared to 2020, mainly due to lower availability and lower precipitation.

Ancillary service volumes for 2021 increased by 40 GWh compared to 2020, in line with our expectations.

Adjusted EBITDA for 2021 increased by $217 million compared to 2020. Effective Jan. 1, 2021, with the expiration of the Alberta PPA for our Alberta Hydro Assets, these facilities began operating on a merchant basis in the Alberta power market. This eliminated the net payment obligations under the Alberta PPA. With strong availability during periods of market volatility, the Company captured higher energy and ancillary service revenue, partially offset by increased costs related to portfolio management services, dam safety staffing, dredging and station services.

Sustaining capital expenditures for 2021 were $6 million higher than in 2020, due to higher planned outages in 2021.

Wind and Solar

Year ended Dec. 31	2022	2021	2020
Gross installed capacity (MW)[1]	**1,906**	1,906	1,572
LTA (GWh)	**4,950**	4,345	3,916
Availability (%)	**83.8**	91.9	95.1
Contract production (GWh)	**3,182**	2,850	2,871
Merchant production (GWh)	**1,066**	1,048	1,198
Total production (GWh)	**4,248**	3,898	4,069
Wind and Solar revenues	**357**	320	311
Environmental attribute revenues	**50**	28	23
Revenues[2]	**407**	348	334
Fuel and purchased power	**31**	17	25
Carbon compliance	**1**	—	—
Gross margin[2]	**375**	331	309
OM&A	**68**	59	53
Taxes, other than income taxes	**12**	10	8
Net other operating income[2]	**(16)**	—	—
Adjusted EBITDA[2]	**311**	262	248
Supplemental information:			
Sustaining capital	**18**	13	13
Kent Hills wind rehabilitation expenditures[3]	**77**	—	—
Insurance proceeds - Kent Hills	**(7)**	—	—

(1) The gross installed capacity in 2022 and 2021 includes incremental capacity related to new facilities: Windrise wind facility (206 MW), North Carolina Solar facility (122 MW) and Oldman wind facility (4 MW).
(2) For details of the adjustments to revenues and net other operating income included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) The Kent Hills wind facilities rehabilitation capital expenditures are segregated from the sustaining capital expenditures due to the extraordinary nature of the expenditures and have been reflected separately.

2022

Availability for the year ended Dec. 31, 2022, decreased compared to 2021, primarily as a result of the extended outage at the Kent Hills 1 and 2 wind facilities.

Production for the year ended 2022 increased 350 GWh compared to 2021, primarily due to higher production from the addition of the Windrise wind facility and the acquisition of the North Carolina Solar facility in the fourth quarter of 2021 and higher wind resources in Eastern Canada, partially offset by lower production from the extended outage at the Kent Hills 1 and 2 wind facilities.

Adjusted EBITDA for 2022 increased by $49 million compared to 2021, primarily due to higher production, higher realized merchant pricing in Alberta, higher environmental attribute revenues and the recognition of liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility. This was partially offset by lower production from the extended outage at Kent Hills, an increase in transmission rates and OM&A related to the addition of the Windrise wind and North Carolina Solar facilities. A one-time favourable adjustment as a result of the AESO transmission line loss ruling was included in 2021.

Sustaining capital expenditures for 2022 were $5 million higher compared to 2021, due to a higher level of major component replacements in 2022.

2021

Availability for the year ended Dec. 31, 2021, decreased compared to 2020, primarily as a result of the unplanned outage at the Kent Hills 1 and 2 wind facilities.

Production for the year ended 2021 decreased 171 GWh compared to 2020 and was impacted by lower wind resources in Eastern Canada and in the US, and the unplanned outage at the Kent Hills 1 and 2 wind facilities, which was partially offset by a full year of production from the Skookumchuck wind facility, the commissioning of the Windrise wind facility and the acquisition of the North Carolina Solar facility.

Adjusted EBITDA for 2021 increased by $14 million compared to 2020, primarily due to higher merchant pricing in Alberta, a full year of operations from the Skookumchuck wind facility and the WindCharger battery storage facility as well as incremental earnings from the newly commissioned or acquired assets in 2021, consisting of the Windrise wind facility and the North Carolina Solar facility. Also, fuel and purchased power costs were lower in 2021 due to the AESO transmission line loss provision recorded in 2020. Adjusted EBITDA was negatively impacted by lower wind resources in Eastern Canada and the US, the unplanned outage at the Kent Hills 1 and 2 wind facilities and the weakening US dollar relative to the Canadian dollar.

Sustaining capital expenditures for 2021 were consistent with 2020.

Kent Hills Rehabilitation

The Kent Hills 1 and 2 wind facilities are not currently in operation following the tower failure event that occurred in September 2021. This event has taken approximately 150 MW of gross production offline temporarily as the Company replaces all 50 turbine foundations at the Kent Hills 1 and 2 wind facilities. The extended outage is expected to result in foregone revenue of approximately $3 million per month on an annualized basis (to the extent all 50 turbines at the Kent Hills 1 and 2 wind facilities are offline), based on average historical wind production, with revenue expected to be earned as the wind turbines are returned to service. Each turbine at Kent Hills 1 and 2 wind facilities will return to service as soon as its foundation is replaced and the turbine is reassembled and tested.

Rehabilitation for the Kent Hills 1 and 2 wind facilities is well underway. The majority of the towers have been fully disassembled including foundation removal. Construction of new foundations is progressing well and the team has now started to re-erect the first turbine tower segments on the new foundations. In addition, the new wind turbine components to replace the damaged unit have been delivered to site. Rehabilitation is targeted to be completed in the second half of 2023. The current estimate of the capital expenditures is approximately $120 million, inclusive of insurance proceeds.

The Company is actively evaluating all options that may be available to recover the rehabilitation costs.

Gas

Year ended Dec. 31	2022	2021	2020
Gross installed capacity (MW)	**3,084**	3,084	3,084
Availability (%)	**94.6**	85.7	87.7
Contract production (GWh)	**3,609**	3,622	7,280
Merchant production (GWh)	**7,927**	7,084	3,698
Purchased power (GWh)	**(88)**	(141)	(198)
Total production (GWh)	**11,448**	10,565	10,780
Revenues[(1)]	**1,521**	1,126	848
Fuel and purchased power[(1)]	**637**	374	221
Carbon compliance	**83**	118	120
Gross margin[(1)]	**801**	634	507
OM&A[(1)]	**195**	173	166
Taxes, other than income taxes	**15**	13	13
Net other operating income	**(38)**	(40)	(39)
Adjusted EBITDA[(1)]	**629**	488	367
Supplemental information:			
Sustaining capital:	**41**	128	87

(1) For details of the adjustments to revenues, fuel and purchased power and OM&A included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2022

Availability for the year ended Dec. 31, 2022, increased compared to 2021, primarily due to lower planned outages with the completion of the coal-to-gas conversions in 2021 and higher reliability of the coal-to-gas converted units compared to coal units.

Production for the year ended Dec. 31, 2022, increased by 883 GWh compared to 2021, mainly due to higher availability and dispatch optimization of the Alberta assets and higher production at the Ada cogeneration facility.

Adjusted EBITDA for the year ended Dec. 31, 2022, increased by $141 million compared to 2021, mainly due to capturing higher realized energy prices through dispatch optimization of our Alberta assets, net of hedging, higher Ontario merchant pricing, steam generation and lower carbon compliance costs. This was partially offset by increased natural gas consumption on recently converted units, higher natural gas prices and higher OM&A due to the Company's performance-related incentive accruals and increased general operating expenses. Carbon compliance costs were lower due to reductions in GHG emissions and utilization of compliance credits to settle a portion of the GHG obligation, partially offset by an increase in the carbon price per tonne and higher production. Lower GHG emissions were a direct result of operating exclusively on natural gas in Alberta rather than coal. Adjusted EBITDA for 2021 was also impacted by the unplanned short-term steam supply outages at the Sarnia cogeneration facility in 2021.

Sustaining capital expenditures for the year ended Dec. 31, 2022, decreased by $87 million compared to 2021, due to the coal-to-gas conversions being completed in 2021.

2021

Availability for the year ended Dec. 31, 2021, decreased compared to 2020, primarily as a result of an increase in unplanned outages and planned boiler conversions of Keephills Unit 2, Keephills Unit 3 and Sheerness Unit 1 in Alberta, partially offset by higher availability of Sundance Unit 6 with its gas conversion having been completed in 2020.

Production for the year ended Dec. 31, 2021, decreased by 215 GWh compared to 2020, mainly due to higher portfolio optimization activities in Alberta and lower customer loads in Australia, partially offset by higher demand at other facilities and incremental production from a full year of operations at the Ada cogeneration facility.

Adjusted EBITDA for the year ended Dec. 31, 2021, increased by $121 million compared to 2020, primarily due to higher merchant pricing in the Alberta market, the South Hedland PPA contract settlement and incremental production from a full year of operations at our Ada cogeneration facility, partially offset by an increase in fuel costs, unplanned short-term steam supply outages at our Sarnia cogeneration facility, higher OM&A costs related to the new projects being constructed under the PPA with BHP and legal fees related to the South Hedland PPA contract settlement.

Sustaining capital expenditures for the year ended Dec. 31, 2021, increased by $41 million mainly due to major maintenance costs associated with conversion to natural gas outages of Keephills Unit 2 and Unit 3 and Sheerness Unit 1, planned major maintenance at the Australian gas facilities and the purchase of an additional engine at the South Hedland facility.

Energy Transition

Year ended Dec. 31	2022	2021	2020
Gross installed capacity (MW)[1]	**671**	1,472	2,548
Availability (%)	**77.2**	75.3	82.6
Adjusted availability (%)[2]	**79.0**	78.8	91.3
Contract sales volume (GWh)	**3,329**	3,329	5,526
Merchant sales volume (GWh)	**3,951**	6,052	6,248
Purchased power (GWh)	**(3,706)**	(3,675)	(3,775)
Total production (GWh)	**3,574**	5,706	7,999
Revenues[3]	**724**	728	690
Fuel and purchased power[3]	**566**	432	352
Carbon compliance	**(1)**	60	48
Gross margin[3]	**159**	236	290
OM&A[3]	**69**	97	106
Taxes, other than income taxes	**4**	6	9
Adjusted EBITDA[3]	**86**	133	175
Supplemental information:			
Highvale mine reclamation spend	**12**	6	7
Centralia mine reclamation spend	**16**	9	7
Sustaining capital	**19**	19	22

(1) The gross installed capacity for 2022, excludes Keephills Unit 1 (395 MW retired on Dec. 31, 2021) and Sundance Unit 4 (406 MW retired on March 31, 2022). The gross installed capacity for 2021 excludes Centralia Unit 1 (670 MW retired on Dec. 31, 2020) and Sundance Unit 5 (406 MW).
(2) Adjusted for dispatch optimization.
(3) For details of the adjustments to revenues, fuel and purchased power and OM&A included in adjusted EBITDA refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2022

Adjusted availability for the year ended Dec. 31, 2022, was consistent with 2021 as higher availability from lower planned and unplanned outages at Centralia Unit 2 was partially offset by the retirements of Sundance Unit 4 in 2022 and Keephills Unit 1 in 2021.

Production decreased by 2,132 GWh for the year ended Dec. 31, 2022, compared to 2021, primarily due to the retirements of Keephills Unit 1 and Sundance Unit 4, partially offset by increased production from higher availability at Centralia Unit 2.

Adjusted EBITDA decreased by $47 million for the year ended Dec. 31, 2022, as compared to 2021, primarily due to the retirement of the Alberta coal assets and higher purchased power costs during outages at Centralia in 2022, partially offset by higher merchant and contract prices and higher production at Centralia, lower carbon costs in Alberta related to utilization of our compliance credits to settle the 2021 GHG obligation and lower OM&A as a result of the retirements on the coal fleet in 2021.

Mine reclamation spend for the Highvale and Centralia mines increased due to the advancement of reclamation activities compared to 2021.

Sustaining capital expenditures for the year ended Dec. 31, 2022, was consistent compared to 2021.

2021

Adjusted availability for the year ended Dec. 31, 2021, decreased compared to 2020 due to higher planned and unplanned outages at Centralia Unit 2 and Sundance Unit 4 related to derates.

Production decreased by 2,293 GWh for the year ended Dec. 31, 2021, compared to 2020, primarily due to the planned retirement of Centralia Unit 1 and dispatch optimization of the Alberta assets.

Adjusted EBITDA decreased by $42 million for the year ended Dec. 31, 2021, compared to 2020, primarily due to the planned retirement of Centralia Unit 1, higher fuel and purchased power costs due to unplanned outages at Centralia Unit 2, higher carbon compliance costs for the Alberta assets primarily due to an increase in carbon prices, and the weakening of the US dollar relative to the Canadian dollar throughout the year, partially offset by dispatch optimization of the Alberta assets and lower OM&A as a result the planned retirement of Centralia Unit 1.

Mine reclamation spend for the Highvale and Centralia mines was consistent compared to 2020.

Sustaining capital expenditures for the year ended Dec. 31, 2021, were $3 million lower than 2020 mainly due to a reduction in planned outage work performed.

Energy Marketing

Year ended Dec. 31	2022	2021	2020
Revenues(1)	**218**	202	133
OM&A	**35**	36	30
Adjusted EBITDA(1)	**183**	166	103

(1) For details of the adjustments to revenues included in adjusted EBITDA, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

2022

Adjusted EBITDA for 2022 increased by $17 million compared to 2021. Results exceeded segment expectations due to short-term trading of both physical and financial power and gas products across all North American deregulated markets. The Company was able to capitalize on short-term volatility in the trading markets without materially changing the risk profile of the business unit.

2021

Adjusted EBITDA for 2021 increased by $63 million compared to 2020. Results were stronger primarily due to favourable short-term trading of both physical and financial power, and natural gas products across all North American markets. This was partially offset by OM&A increases due to higher incentives related to stronger performance. The Energy Marketing team was able to capitalize on short-term volatility in the markets in which we trade without materially changing the risk profile of the business unit.

Corporate

Year ended Dec. 31	2022	2021	2020
OM&A	**101**	84	80
Taxes, other than income taxes	**1**	1	1
Adjusted EBITDA	**(102)**	(85)	(81)
Adjusted EBITDA	**(102)**	(85)	(81)
Total return swap (gains) losses	**1**	(4)	3
CEWS funding received	**—**	(8)	—
CEWS funding applied to incremental employment	**5**	3	—
Adjusted EBITDA excluding impact of total return swap and CEWS	**(96)**	(94)	(78)
Supplemental information:			
Sustaining capital:	**29**	13	14

2022

Adjusted EBITDA for the year ended Dec. 31, 2022, decreased by $17 million compared to 2021, primarily due to higher incentive accruals reflecting the Company's performance. The 2021 adjusted EBITDA was positively impacted by the receipt of CEWS proceeds and gains on the total return swap.

For the year ended Dec. 31, 2022, sustaining capital expenditures increased by $16 million, compared to 2021, mainly due to higher spend on leasehold improvements associated with the relocation of the Company's head office.

2021

Adjusted EBITDA for the year ended Dec. 31, 2021, decreased by $4 million compared to 2020, primarily due to higher incentive payments, higher employee costs, higher insurance costs and higher legal fees for settlement of outstanding legal issues, partially offset by the receipt of CEWS funding and realized gains from the total return swap. A portion of the settlement costs of our employee share-based payment plans is hedged by entering into total return swaps, which are cash settled every quarter. Excluding the impact of the total return swap, staffing costs increased due to additional headcount to support growth initiatives. As previously committed, the CEWS funding is being used to support incremental employment within the Company.

For the year ended Dec. 31, 2021, sustaining capital expenditures were consistent with 2020.

Performance by Segment with Supplemental Geographical Information

The following table provides adjusted EBITDA performance of our facilities across the regions we operate in:

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition(1)	Energy Marketing(2)	Corporate	Total
Alberta	515	114	404	(18)	183	(102)	1,096
Canada, excluding Alberta	12	106	87	—	—	—	205
US	—	91	8	104	—	—	203
Australia	—	—	130	—	—	—	130
Adjusted EBITDA(3)	**527**	**311**	**629**	**86**	**183**	**(102)**	**1,634**
Earnings before income taxes							**353**

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition(1)	Energy Marketing(2)	Corporate	Total
Alberta	308	63	263	59	166	(85)	774
Canada, excluding Alberta	14	120	75	—	—	—	209
US	—	79	10	74	—	—	163
Australia	—	—	140	—	—	—	140
Adjusted EBITDA(3)(4)	322	262	488	133	166	(85)	1,286
Loss before income taxes							(380)

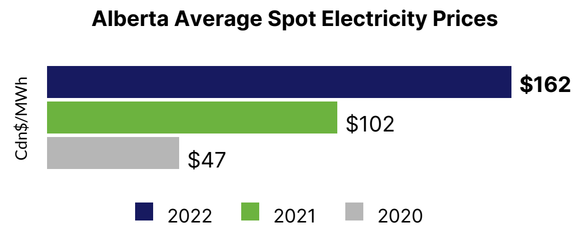
(1) Keephills Unit 1 was retired Dec. 31, 2021, and Sundance Unit 4 was retired March 31, 2022.
(2) The adjusted EBITDA for the Energy Marketing segment was reclassified to the Alberta region to reflect where the operations reside.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Presenting this from period to period provides management and investors with the ability to evaluate earnings (loss) trends more readily in comparison with prior periods' results. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(4) In 2022, adjustments to the Gas and Energy Marketing segments were made for the impact of realized gains and losses on closed exchange positions for these segments in 2021. Also refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Alberta Electricity Portfolio

Generating capacity in Alberta is subject to market forces, rather than rate regulation. Power from commercial generation is cleared through a wholesale electricity market. Power is dispatched in accordance with an economic merit order administered by the Alberta Electric System Operator ("AESO"), based upon offers by generators to sell power in the real-time energy-only market. Our merchant Alberta fleet operates under this framework and we internally manage our offers to sell power.

Approximately 52 per cent of our gross installed capacity is located in Alberta. Our portfolio of merchant assets in Alberta consists of hydro facilities, wind facilities, a battery storage facility, cogeneration facilities and converted natural-gas-fired thermal facilities. Some of the wind and gas facilities within the Alberta Electricity Portfolio operate on long-term contracts. Optimization of portfolio performance is driven by the diversity of fuel types, which enables portfolio management and allows for maximization of operating margins. It also provides us with capacity that can be monetized as ancillary services or dispatched into the energy market during times of supply tightness. A portion of the installed generation capacity in the portfolio has been hedged to provide cash flow certainty.

Alberta's annual demand increased approximately 1.7 per cent from 2021 to 2022, due to the economic recovery from the COVID-19 pandemic, higher residential cooling demand in summer and stronger market conditions for energy commodities supporting power demand. The average pool price increased from $102/MWh in 2021 to $162/MWh in 2022. Pool prices were higher in the second through fourth quarters of 2022 compared to 2021, as a result of higher demand in the province, higher natural gas and carbon prices and stronger prices in an adjacent power market. August and December, specifically, were months with significant weather-driven demand in the province.



Year ended Dec. 31	2022 Hydro	2022 Wind & Solar	2022 Gas	2022 Energy Transition	2022 Total	2021 Hydro	2021 Wind & Solar	2021 Gas	2021 Energy Transition	2021 Total	2020 Hydro	2020 Wind & Solar	2020 Gas	2020 Energy Transition	2020 Total
Total production (GWh)(1)	**1,665**	**1,686**	**8,106**	**19**	**11,476**	1,586	1,319	7,281	2,591	12,777	1,779	1,320	7,732	2,865	13,696
Contract production (GWh)	**—**	**620**	**526**	**—**	**1,146**	—	271	509	—	780	1,703	122	4,223	2,187	8,235
Merchant production (GWh)	**1,665**	**1,066**	**7,580**	**19**	**10,330**	1,586	1,048	6,772	2,591	11,997	76	1,198	3,509	678	5,461
Revenues(2)	**583**	**155**	**989**	**6**	**1,733**	358	97	674	257	1,386	126	57	482	207	872
Fuel and purchased power(3)	**18**	**21**	**442**	**5**	**486**	13	9	258	92	372	6	15	151	73	245
Carbon compliance	**—**	**1**	**70**	**(1)**	**70**	—	—	96	60	156	—	—	120	48	168
Gross margin	**565**	**133**	**477**	**2**	**1,177**	345	88	320	105	858	120	42	211	86	459

(1) Units in the Gas and Energy Transition segments in the prior periods operated on coal. Keephills Unit 1 was retired on Dec. 31, 2021, and Sundance Unit 4 was retired on March 31, 2022.
(2) Revenue has been adjusted to exclude the impact of unrealized mark-to-market gains or losses and realized gains and losses on closed exchange positions in order to depict revenue realized in the year.
(3) Adjustments to fuel and purchased power include the impact of coal mine depreciation and coal inventory write-downs at the Highvale mine in 2021.

For the year ended Dec. 31, 2022, the Alberta Electricity Portfolio generated 11,476 GWh of energy, a decrease of 1,301 GWh compared to 2021. Production was impacted by the retirement of Keephills Unit 1 on Dec. 31, 2021, and Sundance Unit 4 on March 31, 2022. Lower production from the retirement of assets was partially offset by higher contract production mainly due to the Windrise wind facility, commissioned in the fourth quarter of 2021, and higher merchant production benefiting from higher availability in the Hydro segment. Higher merchant production related to the Gas segment was due to more market opportunities for our merchant gas fleet in the second half of 2022.

Gross margin for the year ended Dec. 31, 2022, was $1,177 million, an increase of $319 million compared to 2021. Higher merchant margins were realized through dispatch optimization and the increase in realized power prices, which more than offset higher fuel costs from increased natural gas prices in 2022 as compared to the prior year. Periods of strong weather-driven demand and unplanned outages resulted in opportunities for each of our fuel types in the Alberta Electricity Portfolio throughout the year.

The following table provides information for the Company's Alberta Electricity Portfolio:

Year ended Dec. 31	2022	2021	2020
Spot power price average per MWh	**$162**	$102	$47
Natural gas price (AECO) per GJ	**$5.08**	$3.39	$2.11
Carbon compliance price per tonne	**$50**	$40	$30
Realized merchant power price per MWh(1)(2)	**$126**	$91	$64
Hydro energy spot power price per MWh	**$197**	$122	$—
Hydro ancillary spot price per MWh	**$76**	$55	$—
Wind energy spot power price per MWh	**$90**	$63	$—
Gas and Energy Transition spot power price per MWh	**$194**	$114	$—
Hedged volume (GWh)(2)(3)	**7,228**	6,992	5,395
Hedged power price average per MWh(2)	**$86**	$72	$54
Fuel and purchased power per MWh(4)	**$60**	$38	$23
Carbon compliance cost per MWh(4)	**$9**	$16	$16

(1) Realized merchant power price for the Alberta Electricity Portfolio is the average price realized as a result of the Company's merchant power sales (excluding assets under long-term contract and ancillary revenues) and portfolio optimization activities divided by total merchant GWh produced. In 2020, the realized price was based on the average price realized as a result of the portfolio under PPAs.
(2) In 2020, the portfolio in Alberta was under PPAs and the PPA volumes are not included in the total hedged volumes listed above.
(3) Hedge volumes are for production volumes primarily from the Gas segment.
(4) Fuel and purchased power per MWh and carbon compliance cost per MWh are calculated on production from carbon-emitting generation in the Gas and Energy Transition segments, and carbon compliance cost per MWh includes compliance credits to settle a portion of our GHG carbon pricing obligations.

For the year ended Dec. 31, 2022, the realized merchant power price per MWh of production increased by $35 per MWh, compared with the same period in 2021. Higher realized merchant power pricing for energy across the fleet was due to higher market prices, increased price volatility and optimization of our available capacity across all fuel types. The segment spot prices exclude gains and losses from hedging positions that are entered into in order to mitigate the impact of unfavourable market pricing.

For the year ended Dec. 31, 2022, the fuel and purchased power cost per MWh of production increased by $22 per MWh compared to the same period in 2021, due to higher natural gas pricing and higher fixed gas transportation costs, partially offset by our hedge positions for gas prices and lower coal costs due to the cessation of mining operations in 2021.

For the year ended Dec. 31, 2022, carbon compliance costs per MWh of production decreased by $7 per MWh in the same period in 2021, due to lower carbon emissions from the retirement of our coal fleet and the utilization of compliance credits to settle a portion of our GHG carbon pricing obligation for 2021. Carbon compliance prices have increased to $50 per tonne from $40 per tonne; however, the shift to gas-fired generation effectively lowered our GHG compliance costs as natural gas combustion produces lower GHG emissions than coal combustion.

Fourth Quarter Highlights

Consolidated Financial Highlights

Three months ended Dec. 31	2022	2021
Adjusted availability (%)	**89.5**	83.8
Production (GWh)	**6,005**	5,823
Revenues	**854**	610
Fuel and purchased power(1)	**446**	266
Carbon compliance	**27**	39
Operations, maintenance and administration(1)	**157**	130
Adjusted EBITDA(2)(3)	**541**	243
Earnings (loss) before income taxes	**7**	(32)
Net loss attributable to common shareholders	**(163)**	(78)
Cash flow from operating activities	**351**	54
FFO(2)(3)	**459**	186
FCF(2)(3)	**315**	79
Net loss per share attributable to common shareholders, basic and diluted	**(0.61)**	(0.29)
Dividends declared per common share(4)	**0.11**	0.10
Dividends declared per preferred share(4)	**0.34**	0.25
FFO per share(2)(5)	**1.71**	0.69
FCF per share(2)(5)	**1.17**	0.29

(1) In 2021, $6 million was reclassified from OM&A to fuel and purchased power for station service costs in the Hydro segment.
(2) These items are not defined and have no standardized meaning under IFRS. Refer to the Segmented Financial Performance and Operating Results section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) During 2022, our adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and Energy Marketing segment in the period in which the transactions occur. Therefore, the Company has applied this composition to all previously reported periods.
(4) Weighted average of the Series A, B, C, D, E and G preferred share dividends declared. Dividends declared vary year over year due to timing of dividend declarations.
(5) Funds from operations ("FFO") per share and free cash flow ("FCF") per share are calculated using the weighted average number of common shares outstanding during the period. The weighted average number of common shares outstanding for the three months ended Dec. 31, 2022, was 269 million shares (2021 – 271 million shares). Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the purpose of these non-IFRS ratios.

Financial Highlights

During the fourth quarter of 2022, the Company completed the year with exceptional performance in all of our generation segments as well as our Energy Marketing segment. The Hydro, Wind and Gas facilities in the Alberta Electricity Portfolio had high availability during periods of peak pricing, which resulted from extreme cold weather and periods of province-wide planned and unplanned outages. The Alberta Electricity Portfolio was positioned to capture opportunities from these strong spot market conditions through both energy and ancillary services revenues.

Adjusted availability for the three months ended Dec. 31, 2022, was 89.5 per cent compared to 83.8 per cent for the same period in 2021, mainly due to lower outages at our Alberta gas facilities and at Centralia Unit 2.

Production for the three months ended Dec. 31, 2022, was 6,005 GWh compared to 5,823 GWh for the same period in 2021. The increase in production for the three-month period in 2022 was due to higher availability of the Alberta gas facilities within the Gas segment and Centralia Unit 2 within the Energy Transition segment, partially offset by the retirement of Keephills Unit 1 and Sundance Unit 4.

Revenues for the three months ended Dec. 31, 2022, increased by $244 million compared to the same period in 2021, mainly as a result of capturing higher realized energy prices within the Alberta electricity market through our optimization and operating activities and higher realized ancillary services prices and volumes in the Hydro segment. Revenues further increased due to higher merchant prices and volumes at Centralia Unit 2. These increases were partially offset by the retirement of Keephills Unit 1 and Sundance Unit 4 within the Energy Transition segment.

Fuel and purchased power costs increased by $180 million in the three months ended Dec. 31, 2022, compared to the same period in 2021. The increase is due to higher natural gas prices and higher consumption of natural gas within our Gas segment, partially offset by our hedged positions on gas, lower coal costs and mine depreciation due to the termination of all coal-mining activities in Canada as of Dec. 31, 2021. In addition, fuel and purchased power costs at Centralia were higher from the acquisition of higher-priced power to fulfil our contractual obligations during periods of higher merchant pricing at Centralia Unit 2.

Carbon compliance costs decreased by $12 million in the three months ended Dec. 31, 2022, compared to the same period in 2021, primarily due to reductions in GHG emissions stemming from changes in the fuel mix ratio as we operated more on natural gas and fired less with coal, partially offset by increased production and an increase in the carbon price per tonne.

OM&A expenses for the three months ended Dec. 31, 2022, increased by $27 million, compared to the same period in 2021, primarily due to higher incentive accruals reflecting the Company's performance and increased staffing costs for growth and strategic initiatives.

Adjusted EBITDA for the three months ended Dec. 31, 2022, increased by $298 million compared to the same period in 2021, largely due to higher adjusted EBITDA in our Hydro and Gas segments, which was driven by higher realized prices in the Alberta market, higher adjusted EBITDA in the Wind and Solar segment from higher wind resources in Eastern Canada and higher gross margin from our Energy Marketing segment. This was partially offset by lower adjusted EBITDA in the Energy Transition segment from the retirement of Keephills Unit 1 and Sundance Unit 4, partially offset by higher realized merchant prices and production at Centralia Unit 2.

Net loss attributable to common shareholders in the fourth quarter of 2022 was $163 million compared to a net loss of $78 million in the same period of 2021, an increase of $85 million. The net loss in 2022 was impacted by higher depreciation and amortization expense due to the acceleration of useful lives on certain facilities in our Gas segment, higher OM&A expenses and higher income tax expense due to higher earnings before tax and current and prior period tax adjustments in the US to mitigate cash tax. These unfavourable impacts were partially offset by lower asset impairments, higher gains on sale of assets and other due to the timing of asset sales and higher adjusted EBITDA.

Cash flow from operating activities in the fourth quarter of 2022 increased by $297 million compared to the same period in 2021, mainly due to higher revenues net of unrealized gains and losses from risk management activities and favourable changes in working capital from movements in the collateral accounts related to high commodity prices and volatility in the markets, partially offset by higher fuel and purchased power costs and higher current income tax expense.

FCF in the fourth quarter of 2022 was $315 million compared to $79 million in the same period of 2021, as a result of higher adjusted EBITDA due to Alberta Electricity Portfolio performance and favourable changes in provisions from 2021, partially offset by higher current tax expense, higher distributions paid to subsidiaries' non-controlling interests, higher realized foreign exchange losses, and higher sustaining capital expenditures.

Segmented Financial Performance and Operating Results for the Fourth Quarter

A summary of our adjusted EBITDA by segment and earnings (loss) before income taxes for the three months ended Dec. 31, 2022, and 2021 is as follows:

	Adjusted EBITDA	
Three months ended Dec. 31	**2022**	**2021**
Hydro	**133**	67
Wind and Solar	**92**	76
Gas	**264**	103
Energy Transition	**19**	37
Energy Marketing	**63**	(11)
Corporate	**(30)**	(29)
Total adjusted EBITDA	**541**	243
Earnings (loss) before income taxes	**7**	(32)

Adjusted EBITDA increased by $298 million for the fourth quarter of 2022, compared to 2021, primarily as a result of:

- Hydro results were $66 million higher due to increased revenues from higher merchant and ancillary prices in the Alberta market.
- Wind and Solar results were $16 million higher due to higher merchant pricing in Alberta, higher wind resource in Eastern Canada, higher environmental attribute revenue, higher revenues related to the addition of the Windrise wind and North Carolina Solar facilities, and recognition of liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility.
- Gas results were $161 million higher mainly due to dispatch optimization and higher merchant prices, net of hedging in Alberta and a contract settlement. This was partially offset by the higher cost of natural gas and OM&A related to general operating expenses.
- Energy Transition results were $18 million lower as a result of the retirement of Alberta coal assets, partially offset by higher production and higher contract and merchant pricing at Centralia Unit 2.
- Energy Marketing results were higher by $74 million compared to the same period in 2021. Results exceeded expectations due to short-term trading of both physical and financial power and gas products across all North American deregulated markets.
- Corporate costs were comparable to 2021.

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; 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 2022	Q2 2022	Q3 2022	Q4 2022
Revenues	735	458	929	**854**
Earnings (loss) before income taxes	242	(22)	126	**7**
Cash flow (used in) from operating activities[(1)]	451	(129)	204	**351**
Net earnings (loss) attributable to common shareholders	186	(80)	61	**(163)**
Net earnings (loss) per share attributable to common shareholders, basic and diluted[(2)]	0.69	(0.30)	0.23	**(0.61)**
	Q1 2021	**Q2 2021**	**Q3 2021**	**Q4 2021**
Revenues	642	619	850	610
Earnings (loss) before income taxes	21	72	(441)	(32)
Cash flow from operating activities	257	80	610	54
Net loss attributable to common shareholders	(30)	(12)	(456)	(78)
Net loss per share attributable to common shareholders, basic and diluted[(2)]	(0.11)	(0.04)	(1.68)	(0.29)

(1) The cash flow used in operating activities for the second quarter of 2022 was due to unfavourable changes in working capital mainly due to movements in our collateral accounts related to higher commodity prices and volatility in the markets.

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

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

- Higher revenues arising from higher overall availability during periods of peak pricing and higher power prices in Alberta in 2022;
- Higher natural gas pricing and increased natural gas consumption for the units that were converted to gas in 2021 and 2020;
- Lower carbon costs in 2022 related to our transition off coal and the utilization of renewable energy compliance credits to settle a portion of our GHG obligation in the second quarter of 2022;
- The continued extended outage of the Kent Hills 1 and 2 wind facilities from the fourth quarter of 2021 through the fourth quarter of 2022. The extended outage is expected to continue into 2023;
- The effects of asset impairment charges and reversals during all periods shown;
- The effects of changes in decommissioning provisions for retired assets from changes in estimated cash flows and discount rates in all periods shown;
- Accelerated timing of decommissioning cash flows and changes in useful lives recognized in the third quarter of 2022;
- Insurance proceeds for the single tower failure at Kent Hills wind facilities of $7 million recognized in the second quarter of 2022;
- Liquidated damages recoverable from turbine availability being below the contractual target at the Windrise wind facility were recorded in each of the quarters in 2022;
- Keephills Unit 1 being retired in the fourth quarter of 2021 and Sundance Unit 4 being retired in the first quarter of 2022;
- Acquisition of North Carolina Solar facility in the fourth quarter of 2021;
- Commissioning of the Windrise wind facility in the fourth quarter of 2021;
- The suspension of the Sundance Unit 5 repowering project in the third quarter of 2021;
- The retirement of the Sundance Unit 5 during 2021;
- Gains relating to the sales of assets being recognized in the fourth quarter of 2022, the sale of the Pioneer Pipeline in the second quarter of 2021 and gains on sale of Gas equipment in the third quarter of 2021;
- The unplanned steam supply outages at the Sarnia facility in the second quarter of 2021;
- Receipt of CEWS funding in 2021;
- Accelerated plans to shut down the Highvale mine resulting in remaining future royalty payments being recognized as an onerous contract in the third quarter of 2021;
- Accelerated shutdown of the Highvale mine increasing mine depreciation included in the cost of coal. Coal inventory write-down incurred in the first three quarters of 2021;
- Coal-related parts and materials inventory write-down incurred in the second and third quarters of 2021;
- The impact of the updated provision estimates for the AESO transmission line loss ruling during the first quarter of 2021;
- Fluctuations in the Canadian dollar relative to the US dollar resulting in foreign exchange gains and losses on our US denominated long-term debt balances not designated as hedges; and
- Current and future tax expense fluctuating with earnings before tax across the quarters. Future tax expense increased from 2021 mainly due to a deferred tax write-down taken against part of the Canadian operations and losses on mark-to-market hedging.

Financial Position

The following table highlights significant changes in the Consolidated Statements of Financial Position from Dec. 31, 2021, to Dec. 31, 2022:

Assets	Dec. 31, 2022	Dec. 31, 2021	Increase/ (decrease)
Current assets			
Cash and cash equivalents	**1,134**	947	187
Trade and other receivables	**1,589**	651	938
Risk management assets	**709**	308	401
Other current assets(1)	**282**	291	(9)
Total current assets	**3,714**	2,197	1,517
Non-current assets			
Risk management assets	**161**	399	(238)
Property, plant and equipment, net	**5,556**	5,320	236
Other non-current assets(2)	**1,310**	1,310	—
Total non-current assets	**7,027**	7,029	(2)
Total assets	**10,741**	9,226	1,515
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**1,346**	689	657
Risk management liabilities	**1,129**	261	868
Long-term debt and lease liabilities (current)	**178**	844	(666)
Other current liabilities(3)	**235**	137	98
Total current liabilities	**2,888**	1,931	957
Non-current liabilities			
Credit facilities, long-term debt and lease liabilities	**3,475**	2,423	1,052
Decommissioning and other provisions (long-term)	**659**	779	(120)
Risk management liabilities (long-term)	**333**	145	188
Defined benefit obligation and other long-term liabilities	**294**	253	41
Other non-current liabilities(4)	**1,103**	1,102	1
Total non-current liabilities	**5,864**	4,702	1,162
Total liabilities	**8,752**	6,633	2,119
Equity			
Equity attributable to shareholders	**1,110**	1,582	(472)
Non-controlling interests	**879**	1,011	(132)
Total equity	**1,989**	2,593	(604)
Total liabilities and equity	**10,741**	9,226	1,515

(1) Includes restricted cash, prepaid expenses, inventory and assets held for sale.
(2) Includes investments, long-term portion of finance lease receivables, right-of-use assets, intangible assets, goodwill, deferred income tax assets and other assets.
(3) Includes bank overdraft, current portion of decommissioning and other provisions, current portion of contract liabilities, income taxes payable and dividends payable.
(4) Includes exchangeable securities, deferred income tax liabilities and contract liabilities.

Significant changes in TransAlta's Consolidated Statements of Financial Position were as follows:

Working Capital

Current assets increased by $1,517 million to $3,714 million as at Dec. 31, 2022, from $2,197 million as at Dec. 31, 2021, primarily due to strong Alberta pricing which has increased operating cash flow and higher trade and other receivables due to higher revenue, along with higher collateral posted and higher risk management assets resulting from volatility in market prices. As at Dec. 31, 2022, the Company had provided $304 million (2021 – $55 million) of cash collateral related to derivative instruments in a net liability position.

Current liabilities increased by $957 million from $1,931 million as at Dec. 31, 2021, to $2,888 million as at Dec. 31, 2022, mainly due to an increase in accounts payable and accrued liabilities due to higher payables for increased construction activities. Additionally, higher payables in the Energy Market segment, higher collateral received associated with counterparty obligations and an increase in risk management liabilities arose primarily due to volatility in market prices across multiple markets. These increases were partially offset by the repayment of the US$400 million of 4.50 per cent unsecured senior notes due in 2022 and the reclassification of the KH Bonds of $206 million to long-term liabilities as the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities which supported the reclassification to long-term debt. As at Dec. 31, 2022, the Company held $260 million (2021 – $18 million) of cash collateral received related to derivative instruments in a net asset position.

The excess of current assets over current liabilities, including the current portion of long-term debt and lease liabilities, was $826 million as at Dec. 31, 2022 (2021 – $266 million). Our working capital increased year over year mainly due to the reclassification of the KH Bonds from current to long-term liabilities, as well as the repayment of the US$400 million of 4.50 per cent unsecured senior notes due in 2022. The year-over-year increase was also due to an increase in cash of $187 million and higher trade and other receivables of $938 million due to strong Alberta merchant pricing, including higher collateral provided, and higher risk management assets of $401 million primarily from volatility in market prices. The increase was partially offset by higher accounts payable, including collateral held, of $657 million and higher risk management liabilities of $868 million primarily from the volatility in market prices. Excluding the current portion of long-term debt and lease liabilities of $178 million (2021 – $844 million), the excess of current assets over liabilities was $1,004 million as at Dec. 31, 2022 (2021 – $1,110 million), slightly lower than the prior year.

Non-Current Assets

Non-current assets as at Dec. 31, 2022, were $7,027 million, a decrease of $2 million from $7,029 million as at Dec. 31, 2021. The decrease was mainly due to lower risk management assets due to volatility in market pricing across multiple markets and contract settlements, primarily offset by an increase in property, plant and equipment ("PP&E"). Additions to PP&E of $918 million were mainly for the construction of the White Rock wind projects, the Garden Plain wind project, the Horizon Hill wind project, the Northern Goldfields solar project and the Kent Hills rehabilitation costs, and other planned major maintenance. The increases to PP&E were partially offset by revisions and additions to decommissioning and restoration costs of $74 million, the impairment of assets of $62 million and depreciation of $538 million.

Non-Current Liabilities

Non-current liabilities as at Dec. 31, 2022, were $5,864 million, an increase of $1,162 million from $4,702 million as at Dec. 31, 2021, mainly due to a $1,052 million increase in long-term debt and lease liabilities related to the Company entering into a two-year $400 million floating rate Term Facility, which was fully drawn at Dec. 31, 2022, and the issuance of the US$400 Senior Green Bonds. The KH Bonds were also reclassified to long-term debt in 2022 as a result of the waiver obtained. This was offset by the non-recourse bonds of Pingston Power Inc. being reclassified to current liabilities during 2022. The increase in risk management liabilities of $188 million is due to the volatility across multiple markets and new contracts, and is offset by lower decommissioning and other provisions of $120 million, and lower defined benefit obligation and other long-term liabilities of $41 million.

Total Equity

As at Dec. 31, 2022, the decrease in total equity of $604 million was due to other comprehensive loss of $424 million, distributions to non-controlling interests of $187 million, share repurchases under the NCIB of $54 million and dividends declared on common and preferred shares of $103 million, partially offset by net earnings of $161 million.

Financial Capital

The Company 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 Company's financing costs, liquidity and operations, and affect the Company's ability to obtain short-term and long-term financing and/or the cost of such financing. Maintaining a strong balance sheet also allows the Company to enter into contracts with a variety of counterparties on terms and prices that are favourable to the Company’s financial results and provide TransAlta with better access to capital markets through commodity and credit cycles.

In 2022, Moody's reaffirmed the Company's Long Term Rating of Ba1 with a stable outlook. DBRS Morningstar reaffirmed the Company's issuer rating and Unsecured Debt/Medium-Term Notes rating of BBB (low) and the Company's Preferred Shares rating of Pfd-3 (low), all with stable outlook. In addition, S&P Global Ratings reaffirmed the Company's Senior Unsecured Debt rating and Issuer Credit Rating of BB+ with stable outlook. Risks associated with our credit ratings are discussed in the Governance and Risk Management section of this MD&A.

Capital Structure

A strong financial position provides the Company with better access to capital markets through commodity and credit cycles. We use total capital to help evaluate the strength of our financial position. Our capital structure consists of the following components as shown below:

As at Dec. 31	2022		2021		2020	
	$	**%**	$	%	**$**	**%**
TransAlta Corporation						
Net senior unsecured debt						
Recourse debt - CAD debentures	**251**	**5**	251	4	249	3
Recourse debt - US senior notes	**934**	**18**	888	16	886	13
Credit facilities	**—**	**—**	—	—	114	2
Term Facility	**396**	**8**	—	—	—	—
Other	**1**	**—**	4	—	7	—
Less: cash and cash equivalents(1)	**(884)**	**(17)**	(703)	(12)	(121)	(2)
Less: other cash and liquid assets(2)	**(20)**	**—**	(19)	—	(13)	—
Net senior unsecured debt	**678**	**14**	421	8	1,122	16
Other debt liabilities						
Exchangeable debentures	**339**	**6**	335	6	330	5
Non-recourse debt						
TAPC Holdings LP bond	**94**	**2**	102	2	111	2
OCP Bond	**241**	**4**	263	5	284	4
Lease liabilities	**112**	**2**	78	1	112	2
Total net debt(3) - TransAlta Corporation	**1,464**	**28**	1,199	22	1,959	29
TransAlta Renewables						
Net TransAlta Renewables reported debt						
Committed credit facility	**32**	**1**	—	—	—	—
Pingston bond	**45**	**1**	45	1	45	1
Melancthon Wolfe Wind bond	**202**	**4**	235	4	268	4
New Richmond Wind bond	**112**	**2**	120	2	127	2
Kent Hills Wind bond	**206**	**4**	221	4	230	3
Windrise Wind bond	**170**	**3**	171	3	—	—
Lease liabilities	**23**	**—**	22	—	22	—
Less: cash and cash equivalents(4)	**(234)**	**(4)**	(244)	(4)	(582)	(9)
Debt on TransAlta Renewables Economic Investments						
US tax equity financing(5)	**123**	**2**	135	2	134	2
South Hedland non-recourse debt(5)	**711**	**14**	732	13	772	11
Total net debt(3) - TransAlta Renewables	**1,390**	**27**	1,437	25	1,016	14
Total consolidated net debt(3)(6)(7)	**2,854**	**55**	2,636	47	2,975	43
Non-controlling interests	**879**	**17**	1,011	18	1,084	16
Exchangeable preferred securities(7)	**400**	**7**	400	7	400	6
Equity attributable to shareholders						
Common shares	**2,863**	**54**	2,901	51	2,896	43
Preferred shares	**942**	**18**	942	17	942	14
Contributed surplus, deficit and accumulated other comprehensive income	**(2,695)**	**(51)**	(2,261)	(40)	(1,486)	(22)
Total capital	**5,243**	**100**	5,629	100	6,811	100

(1) As at Dec. 31, 2022, cash and cash equivalents is net of bank overdraft.
(2) Includes principal portion of OCP restricted cash as this cash is restricted specifically to repay outstanding debt and also includes the fair value of economic and designated hedging instruments on debt, as the carrying value of the related debt is impacted by changes in foreign exchange rates.
(3) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS.
(4) Includes $145 million (AU$158 million) cash held within TransAlta Energy (Australia) Pty Ltd. reserved for future funding of Australia growth projects by TransAlta Renewables.
(5) TransAlta Renewables has an economic interest in the US entities holding these debts and an economic interest in the Australian entities, which includes the AU$786 million (2021 – AU$800 million) senior secured notes.
(6) The tax equity financing for the Skookumchuck wind facility, an equity accounted joint venture, is not represented in these amounts.
(7) The total consolidated net debt excludes the exchangeable preferred securities as they are considered equity with dividend payments for credit purposes.

We continued to strengthen our financial position during 2022 and have sufficient liquidity to fund our growth strategy.

We have enhanced liquidity and shareholder value through the following:

2022

- Issued US$400 million Senior Green Bonds, with a fixed coupon rate of 7.75 per cent per annum, due on Nov. 15, 2029;
- Repaid the US$400 million 4.50 per cent unsecured senior notes due 2022;
- Extended the committed syndicated credit facilities by one year to June 30, 2026 and the committed bilateral credit facilities by one year to June 30, 2024;
- Closed a two-year floating rate Term Facility with our banking syndicate for $400 million with a maturity date of Sep. 7, 2024. The Term Facility has interest rates that vary depending on the option selected (e.g. Canadian prime and bankers' acceptances.); and
- Purchased and cancelled 4,342,300 common shares at an average price of $12.48 per share through our NCIB program, for a total cost of $54 million.

2021

- Obtained $173 million in project financing related to our Windrise wind facility.

2020

- Obtained AU$800 million in project financing related to our South Hedland facility;
- Received the second tranche of $400 million from Brookfield in consideration for redeemable, retractable first preferred shares;
- Redeemed our outstanding 5 per cent $400 million medium-term notes due on Nov. 25, 2020; and
- Purchased and cancelled 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.

Credit Facilities

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

As at Dec. 31, 2022		Utilized			
Credit facilities	**Facility size**	**Outstanding letters of credit[1]**	**Cash drawings**	**Available capacity**	**Maturity date**
Committed					
TransAlta Corporation syndicated credit facility	1,250	738	—	512	Q2 2026
TransAlta Renewables syndicated credit facility	700	—	33	667	Q2 2026
TransAlta Corporation bilateral credit facilities	240	219	—	21	Q2 2024
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**957**	**433**	**1,200**	
Non-Committed					
TransAlta Corporation demand facilities	250	120	—	130	n/a
TransAlta Renewables demand facility	150	98	—	52	n/a
Total Non-Committed	**400**	**218**	**—**	**182**	

(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. Letters of credit drawn against the non-committed facilities reduce available capacity under the committed syndicated credit facilities.

US Tax Equity Financing

The Company owns equity interests in some wind facilities that are eligible for tax incentives available for renewable energy facilities in the US. With its current portfolio of renewable energy facilities, TransAlta cannot fully monetize such tax incentives. To take full advantage of these incentives, the Company partners with Tax Equity Investors ("TEI") who invest in these facilities in exchange for a share of the tax credits.

Some TEI financing structures include a partial pay-as-you-go ("Pay-go") funding arrangement under which, when the actual annual electricity production (MWh) exceeds a certain production threshold, the TEI are obligated to make a cash contribution ("Pay-go contribution") to the Company. The Pay-go arrangement results in a lower initial investment by the TEI and provides them with some protection from potential underperformance of the asset.

TransAlta recognizes the TEI contributions as long-term debt, at an amount representing the proceeds received from the TEI in exchange for shares of subsidiaries of TransAlta, net of the following elements:

Production tax credit ("PTC")	Allocation of PTCs to the TEI derived from the power generated during the period is recognized in other revenues as earned and as a reduction in tax equity financing.
Tax shield	Allocation of tax benefits and attributes to the TEI, such as investment tax credits and tax depreciation, is recognized in net interest expense as claimed and as a reduction in tax equity financing.
Interest expense	Interest expense using the effective interest rate method is recognized in net interest expense as incurred and as an increase in tax equity financing.
Pay-go contributions	Additional cash contributions made by the TEI when the annual production exceeds the contractually determined threshold and is recognized as an increase in tax equity financing.
Cash distributions	Cash payments to the TEI, recognized as a reduction in tax equity financing.

Production Tax Credit Program

Current US tax law allows qualified wind energy projects to receive tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation. The TEIs are allocated a portion of the renewable energy facility's taxable income (losses) and PTCs produced and a portion of the cash generated by the facility until they achieve an agreed-upon after-tax investment return ("Flip Point"). After the Flip Point, the TEI will retain a lesser portion of the cash and the taxable income (losses) generated by the facility.

The following table outlines information regarding the Company's tax equity financing arrangements with PTC eligibility:

Facility	Commercial operation date	Expected Flip Point	Initial TEI investment ($)	Expected annual PTC ($)	Expected annual Pay-go Contribution ($)	TEI allocation of taxable income and PTCs (pre-Flip Point)
Lakeswind	2014	2029	45	4	—	99 %
Big Level and Antrim	2019	2030	126	9	2	99 %
Skookumchuck(1)	2020	2029	121	10	—	99 %

(1) The Company has 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.

Non-Recourse Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd, Windrise Wind LP and TransAlta OCP LP non-recourse bonds, with an aggregate carrying value of $1.8 billion (Dec. 31, 2021 – $1.9 billion), are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2022 with the exception of Kent Hills Wind LP, as discussed below and TAPC Holdings LP, which has been impacted by higher interest rates in 2022. The funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2023. At Dec. 31, 2022, $50 million (Dec. 31, 2021 – $67 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.

Kent Hills Wind Facilities Rehabilitation

During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon receipt of the waiver, the Company reclassified a portion of the carrying value outstanding for the KH Bonds to non-current liabilities with the exception of the scheduled principal repayments due within the next 12 months. In accordance with the supplemental indenture, Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed.

Scheduled Debt Maturities

Between 2023 and 2025, we have $839 million of debt maturing, including $400 million of recourse debt primarily relating to the Term Facility, with the balance mainly related to scheduled non-recourse debt repayments.

Returns to Providers of Capital

Net Interest Expense

The components of net interest expense are shown below:

Year ended Dec. 31	2022	2021	2020
Interest on debt	**164**	163	158
Interest on exchangeable debentures	**29**	29	29
Interest on exchangeable preferred shares	**28**	28	5
Interest income	**(24)**	(11)	(10)
Capitalized interest	**(16)**	(14)	(8)
Interest on lease liabilities	**7**	7	8
Credit facility fees, bank charges and other interest	**27**	20	25
Tax shield on tax equity financing(1)	**(2)**	(9)	1
Accretion of provisions	**49**	32	30
Net interest expense	**262**	245	238

(1) The credit balance in 2022 primarily relates to the tax benefit associated with tax depreciation (2021 – investment tax credits) on the North Carolina Solar facility 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 and investment tax credits (as applicable) is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.

Net interest expense was higher in 2022 primarily due to higher accretion of provisions, higher credit facility fees and other interest due to increased letters of credit issued to support trading and hedging activities, and higher interest paid on cash collateral held as security for counterparty obligations and lower tax shield on tax equity financing. This is partially offset by higher interest income due to favourable interest rates and higher capitalized interest.

Share Capital

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

As at	Feb. 22, 2023	Dec. 31, 2022	Dec. 31, 2021
	Number of shares (millions)		
Common shares issued and outstanding, end of period	**268.2**	**268.1**	271.0
Preferred shares			
Series A(1)	9.6	9.6	9.6
Series B(1)	2.4	2.4	2.4
Series C(2)	10.0	10.0	11.0
Series D(2)	1.0	1.0	—
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(3)	**0.4**	**0.4**	0.4
Preferred shares issued and outstanding, end of period	**39.0**	**39.0**	39.0

(1) During the first quarter of 2021, the Company converted 1,417,338 of its 10,200,000 Series A Shares and 871,871 of its 1,800,000 Series B Shares, on a one-for-one basis, into Series B Shares and Series A Shares, respectively.
(2) During the second quarter of 2022, the Company converted 1,044,299 of its 11,000,000 currently outstanding Series C Shares, on a one-for-one basis, into Series D Shares.
(3) Brookfield invested $400 million in consideration for redeemable, retractable, first preferred shares. For accounting purposes, these preferred shares are considered debt and disclosed as such in the consolidated financial statements.

Dividends to Shareholders

The declaration of dividends is at the discretion of the Board. The following are the common and preferred shares dividends declared in each quarter during 2022:

Declaration date	April 27, 2022	July 27, 2022	Nov. 8, 2022	Dec. 12, 2022
Common shares (Payable date)	July 1, 2022	Oct. 1, 2022	Jan. 1, 2023	April 1, 2023
	Common shares dividends per share			
Common shares	0.0500	0.0500	0.0550	0.0550

Preferred shares (Payable date)	June 30, 2022	Sept. 30, 2022	Dec. 31, 2022	March 31, 2023
	Preferred Series dividends per share			
Series A	0.17981	0.17981	0.17981	0.17981
Series B	0.16505	0.22099	0.33700	0.37991
Series C	0.25169	0.36588	0.36588	0.36588
Series D	0.25169	0.28841	0.40442	0.45578
Series E	0.32463	0.32463	0.43088	0.43088
Series G	0.31175	0.31175	0.31175	0.31175

Non-Controlling Interests

As of Dec. 31, 2022, the Company owns 60.1 per cent (2021 – 60.1 per cent) of TransAlta Renewables. TransAlta Renewables is a publicly traded company whose common shares are listed on the TSX under the symbol “RNW.” TransAlta Renewables holds a diversified, highly contracted portfolio of assets with comparatively lower carbon intensity.

We also own 50.01 per cent of TA Cogen (2021 – 50.01 per cent) , which owns, operates or has an interest in three natural-gas-fired cogeneration facilities (Ottawa, Windsor and Fort Saskatchewan) and one natural-gas-fired facility (Sheerness). Sheerness operated as a dual-fuel generating facility in 2021.

Since we own a controlling interest in TA Cogen and TransAlta Renewables, we consolidate the entire earnings, assets and liabilities in relation to those subsidiaries.

The reported net earnings attributable to non-controlling interests for the year ended Dec. 31, 2022, decreased by $1 million compared to 2021, due to higher TA Cogen net earnings being offset by lower TransAlta Renewables net earnings. TA Cogen net earnings attributable to non-controlling interests has increased by $29 million compared to 2021, primarily due to higher merchant pricing in the Alberta market, partially offset by lower generation due to dispatch optimization.

TransAlta Renewables net earnings attributable to non-controlling interests decreased by $30 million compared to 2021. The decrease was primarily due to lower finance income related to subsidiaries of TransAlta, higher asset impairments primarily related to higher discount rates, higher OM&A, lower foreign exchange gains and higher interest expense from the issuance of the Windrise Green bond in late 2021. In addition, net earnings decreased due to the extended outage at the Kent Hills 1 and 2 wind facilities. The decrease was partially offset by higher revenues and the receipt of insurance proceeds for the replacement costs for the collapsed tower at the Kent Hills site. The Company recognized liquidated damages recoverable due to turbine availability being below the contractual target at the Windrise wind facility. Finance income related to subsidiaries of TransAlta was lower as higher distributions were classified as return of capital. Refer to Note 12 of the consolidated financial statements for further details.

Reported net earnings attributable to non-controlling interests for the year ended Dec. 31, 2021, increased by $78 million to $112 million compared to 2020. Earnings increased at TransAlta Renewables in 2021 mainly due to higher finance income from investments in subsidiaries of TransAlta and no fair value losses recognized in the current year, partially offset by liquidated damages provisions related to unplanned outages at the Sarnia cogeneration facility, unfavourable steam reconciliation adjustment to Canadian Gas, lower wind production from the Canadian wind fleet, lower foreign exchange gains and higher asset impairments. Earnings from TA Cogen were higher in 2021 mainly due to higher prices in the Alberta market.

Other Consolidated Analysis

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.

Related Party Transactions

In the normal course of operations, we enter into transactions on market terms with related parties, including consolidated and equity accounted entities, which have been measured at exchange value and are recognized in the consolidated financial statements, including, but not limited to: asset management fees, power purchase and derivative contracts. Refer to Note 36, Related-Party Transactions in the consolidated financial statements for further details.

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, 2022, we provided letters of credit totalling $1.2 billion (2021 – $902 million) and cash collateral of $304 million (2021 – $55 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 obligations and other long-term liabilities and decommissioning and other provisions. The increase in the amount of letters of credit issued during 2022 relates to the increased collateral required for asset hedging and energy marketing activity, partially offset by lower letters of credit related to pension plan commitments and the Highvale mine pension plan and reclamation obligations.

Proceeds from Divestitures

During 2022, the Company closed the sale of two hydro facilities, sold equipment related to its Sundance Unit 5 energy transition assets, and other equipment. As a result of these sales, the Company received proceeds of $66 million and recorded gains on sale of $32 million. In addition, during the fourth quarter of 2022, the Company recorded a contract settlement that was recognized in gain on sale of assets and other on the Consolidated Statements of Earnings (Loss).

Commitments

Contractual commitments are as follows:

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Natural gas, transportation and other contracts[1]	56	47	45	45	46	457	**696**
Transmission[1]	10	7	7	3	1	39	**67**
Coal supply and mining agreements[1]	83	87	71	—	—	—	**241**
Long-term service agreements[1]	51	49	35	32	21	140	**328**
Operating leases[1,2]	3	3	3	2	2	29	**42**
Long-term debt[3]	170	527	142	177	154	2,393	**3,563**
Exchangeable securities[4]	—	—	750	—	—	—	**750**
Principal payments on lease liabilities[5]	(7)	4	4	3	4	127	**135**
Interest on long-term debt and lease liabilities[1,6]	205	192	166	158	150	836	**1,707**
Interest on exchangeable securities[1,4]	52	62	—	—	—	—	**114**
Growth[1,7]	446	—	—	—	—	—	**446**
TransAlta Energy Transition Bill[1]	6	—	—	—	—	—	**6**
Total	**1,075**	**978**	**1,223**	**420**	**378**	**4,021**	**8,095**

(1) Not recognized as a financial liability on the Consolidated Statements of Financial Position.
(2) Includes leases that have not been recognized as a lease liability and leases that have not yet commenced.
(3) Excludes impact of hedge accounting and derivatives.
(4) Assumes the exchangeable securities will be exchanged by Brookfield on Jan. 1, 2025.
(5) Lease liabilities include a lease incentive of $12 million, expected to be received in 2023.
(6) Interest on long-term debt is based on debt currently in place with no assumption as to refinancing on maturity.
(7) For further details on growth commitments, refer to the Strategy and Capability to Deliver Results section of this MD&A.

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 Company'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 Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Government of Alberta; and (ii) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the Alberta Energy Regulator ("AER"); and (ii) is out of time under the Limitations Act (Alberta). The trial is scheduled to take place during the first quarter of 2024.

Brazeau Facility - Well Licence Applications to Consider Hydraulic Fracturing Activities

The AER issued a subsurface order on May 27, 2019 that does not permit any hydraulic fracturing within three kilometres of the Brazeau facility but permits fracking in all formations (except the Duvernay) from three-to-five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for approval of 10 well licences (which include hydraulic fracturing activities) within three-to-five kilometres of the Brazeau facility. The regulatory hearing to consider the applications - Proceeding 379 - is currently scheduled to be heard between Feb. 27 and March 10, 2023. The Company's position is that hydraulic fracturing activities within any formation within five kilometres of the Brazeau Facility pose an unacceptable risk and that the applications should be denied.

Hydro Power Purchase Arrangement - Emission Performance Credits

Balancing Pool is claiming entitlement to the Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of those facilities being opted into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018 to 2020, inclusive. The Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro Power Purchase Arrangement require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change-in-law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing was scheduled for Feb. 6 to 10, 2023. However, due to the resignation of one of the panel members, the hearing has been adjourned. A new panel member has been appointed and a two-week hearing will be held from May 18 to June 1, 2023. TransAlta holds approximately 1,750,000 EPCs with no recorded book value that were created between 2018 and 2020, which are at risk as a result of the Balancing Pool's claim.

Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission ("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 the second half of 2023. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

Cash Flows

The following highlights significant changes in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2022 and Dec. 31, 2021:

Year ended Dec. 31	2022	2021	Increase/ (decrease)
Cash and cash equivalents, beginning of year	**947**	703	244
Provided by (used in):			
Operating activities	**877**	1,001	(124)
Investing activities	**(741)**	(472)	(269)
Financing activities	**45**	(282)	327
Translation of foreign currency cash	**6**	(3)	9
Cash and cash equivalents, end of year	**1,134**	947	187

Cash from operating activities for the year ended Dec. 31, 2022, decreased compared with 2021 primarily due to higher unfavourable changes in working capital, mainly from higher accounts receivable and collateral paid, partially offset by higher accounts payable and collateral received, and higher fuel and purchased power. Movements in the collateral accounts relate to high commodity prices and volatility in the markets. This was partially offset by higher revenues net of unrealized gains and losses from risk management activities, higher net other operating (income) loss and lower carbon compliance costs.

Cash from investing activities for the year ended Dec. 31, 2022, decreased compared with 2021, largely due to:

- Higher cash spent on growth projects and Kent Hills remediation construction activities in PP&E ($438 million) and investments during the year ($10 million); and
- The prior year included proceeds received on the sale of the Pioneer Pipeline ($128 million) partially offset by:
    - Lower net cash spent on acquisitions ($110 million) as the prior year included the North Carolina Solar acquisition;
    - Favourable change in non-cash working capital related to the timing of construction payables for the assets under construction ($71 million);
    - Higher realized gains on financial instruments ($33 million);
    - Higher proceeds from the sale of property, plant and equipment ($27 million); and
    - Higher loan receivable receipts ($21 million).

Cash from financing activities for the year ended Dec. 31, 2022, increased compared with 2021, largely due to:

- Higher net borrowings under the Company's credit facilities ($563 million);
- Higher proceeds from issuance of long-term debt ($359 million); and
- Higher realized gains on financial instruments ($39 million) partially offset by:
    - Higher repayments of long-term debt ($529 million);
    - Higher common share repurchases under the NCIB ($48 million);
    - Increased distributions paid to subsidiaries' non-controlling interests ($31 million);
    - Higher dividends paid on common shares and preferred shares ($10 million);
    - Higher financing fees and other ($9 million); and
    - Lower proceeds on issuances of common shares ($5 million).

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, 2022, 2021 and 2020. Presenting these line items provides management and investors with a measurement of ongoing operating performance that is readily comparable from period to period.

We use a number of financial measures to evaluate our performance and the performance of our business segments, including measures and ratios that are presented on a non-IFRS basis, as described below. Unless otherwise indicated, all amounts are in Canadian dollars and have been derived from our consolidated financial statements prepared in accordance with IFRS. We believe that these non-IFRS amounts, measures and ratios, read together with our IFRS amounts, provide readers with a better understanding of how management assesses results.

Non-IFRS amounts, measures and ratios do not have standardized meanings under IFRS. They are unlikely to be comparable to similar measures presented by other companies and should not be viewed in isolation from, as an alternative to, or more meaningful than, our IFRS results.

Non-IFRS Financial Measures

Adjusted EBITDA, FFO, FCF, total net debt, total consolidated net debt and adjusted net debt are non-IFRS measures that are presented in this MD&A. Refer to the Segmented Financial Performance and Operating Results, Segmented Financial Performance and Operating Results for the Fourth Quarter, Selected Quarterly Information, Financial Capital and Key Non-IFRS Financial Ratios sections of this MD&A for additional information, including a reconciliation of such non-IFRS measures to the most comparable IFRS measure.

Adjusted EBITDA

Each business segment assumes responsibility for its operating results measured by adjusted EBITDA. Adjusted EBITDA is an important metric for management that represents our core business profitability. In the second quarter of 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Accordingly, the Company has applied this composition to all previously reported periods. Interest, taxes, depreciation and amortization are not included, as differences in accounting treatments may distort our core business results. In addition, certain reclassifications and adjustments are made to better assess results, excluding those items that may not be reflective of ongoing business performance. This presentation may facilitate the readers' analysis of trends.

The following are descriptions of the adjustments made.

Adjustments to revenue

- Certain assets that we own in Canada and in Australia are fully contracted and recorded as finance leases under IFRS. We believe that 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.
- Adjusted EBITDA is adjusted to exclude the impact of unrealized mark-to-market gains or losses and unrealized foreign exchange gains or losses on commodity transactions.
- Gains and losses related to closed positions effectively settled by offsetting positions with exchanges that have been recorded in the period the positions are settled.

Adjustments to fuel and purchased power

- Depreciation on our mining equipment is included in fuel and purchased power.
- Write-downs of coal inventory in 2020 and 2021 are excluded and related to the decision to be off-coal and the accelerated shutdown of the Highvale mine at the end of 2021 and are not reflective of ongoing business performance.
- 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.

Adjustments to operations, maintenance and administration

- Write-down of parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities.
- Curtailment gains resulting from the shutdown Highvale mine and impacting the defined benefit pension plan are excluded as they do not reflect on-going performance.

Adjustments to net other operating income (loss)

- An onerous contract provision for future royalty payments recognized with the shutdown of the Highvale mine is excluded as these are not part of operating income.
- Contract termination penalties as a result of the Company's Clean Energy Transition plan are not included.
- Sheerness facility moving off-coal resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract in 2020, and is excluded.
- Insurance recoveries related to the Kent Hills tower collapse are not included as these relate to investing activities and are not reflective of ongoing business performance.

Adjustments to earnings (loss) in addition to interest, taxes, depreciation and amortization

- Asset impairment charges (reversals) are not included as these are accounting adjustments that impact depreciation and amortization and do not reflect ongoing business performance.
- Any gains or losses on asset sales or foreign exchange gains or losses are not included as these are not part of operating income.

Adjustments for equity accounted investments

- 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 adjusted EBITDA of the Skookumchuck wind facility in our total adjusted EBITDA. In addition, in the Wind and Solar adjusted 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 International, LLC’s adjusted EBITDA in our total adjusted EBITDA as it does not represent our regular power-generating operations.

Average Annual EBITDA

Average annual EBITDA is a non-IFRS financial measure that is forward-looking, used to show the average annual EBITDA that the project currently under construction is expected to generate upon completion.

Funds From Operations ("FFO")

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. FFO is a non-IFRS measure.

Adjustments to cash flow from operations

- Includes FFO related to the Skookumchuk wind facility, which is treated as an equity accounted investment under IFRS and equity income, net of distributions from joint ventures is included in cash flow from operations under IFRS. As this investment is part of our regular power generating operations, we have included our proportionate share of FFO.
- Payments received on finance lease receivables are reclassified to reflect cash from operations.
- We adjust for items included in cash from operations related to the decision in 2020 to accelerate being off-coal and the shutdown of the Highvale mine in 2021, the write-down on parts and material inventory for our coal operations and voluntary contribution made to fund the Sunhills Mining Ltd. Pension Plan in 2022 (grouped in the line item under "Clean energy transition provisions and adjustments").
- Cash received/paid on closed positions are reflected in the period that the position is settled.
- The Company's share of the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results from 2021 onwards due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.
- Other adjustments include payments/receipts for production tax credits, which are reductions to tax equity debt and include distributions from equity accounted joint venture.

Free Cash Flow ("FCF")

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. FCF is a non-IFRS measure.

Non-IFRS Ratios

FFO per share, FCF per share and adjusted net debt to adjusted EBITDA are non-IFRS ratios that are presented in the MD&A. Refer to the Reconciliation of Cash Flow from Operations to FFO and FCF and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

FFO per Share and FCF per Share

FFO per share and FCF per share are calculated using the weighted average number of common shares outstanding during the period. FFO per share and FCF per share are non-IFRS ratios.

Supplementary Financial Measures

Financial highlights presented on a proportional basis of TransAlta Renewables, deconsolidated adjusted EBITDA, deconsolidated FFO and deconsolidated adjusted EBITDA to deconsolidated FFO are supplementary financial measures that the Company uses to present adjusted EBITDA on a deconsolidated basis. Refer to the Financial Highlights on a Proportional Basis of TransAlta Renewables and Key Non-IFRS Financial Ratios sections of this MD&A for additional information.

The Alberta Electricity Portfolio metrics disclosed are also supplementary financial measures used to present the gross margin by segment for the Alberta market. Refer to the Alberta Electricity Portfolio section of this MD&A for additional information.

Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended Dec. 31, 2022:

Three months ended, Dec. 31 2022	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	159	98	276	281	44	—	858	(4)	—	854
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	1	23	238	(7)	12	—	267	—	(267)	—
Realized loss on closed exchange positions	—	—	7	—	20	—	27	—	(27)	—
Decrease in finance lease receivable	—	—	12	—	—	—	12	—	(12)	—
Finance lease income	—	—	4	—	—	—	4	—	(4)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	160	121	537	274	75	—	1,167	(4)	(309)	854
Fuel and purchased power	5	11	196	234	—	—	446	—	—	446
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Adjusted fuel and purchased power	5	11	195	234	—	—	445	—	1	446
Carbon compliance	—	—	27	—	—	—	27	—	—	27
Gross margin	155	110	315	40	75	—	695	(4)	(310)	381
OM&A	22	18	57	19	12	30	158	(1)	—	157
Taxes, other than income taxes	—	5	2	2	—	—	9	(1)	—	8
Net other operating (income) loss	—	(5)	(8)	—	—	—	(13)	3	—	(10)
Adjusted EBITDA[2]	133	92	264	19	63	(30)	541			
Equity income										4
Finance lease income										4
Depreciation and amortization										(188)
Asset impairment charges										(5)
Net interest expense										(67)
Foreign exchange loss										(13)
Gain on sale of assets and other										46
Earnings before income taxes										7

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the three months ended Dec. 31, 2021:

Three months ended, Dec. 31 2021	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	84	98	172	238	26	(2)	616	(6)	—	610
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	3	82	(8)	(12)	—	65	—	(65)	—
Realized gain on closed exchange positions[2]	—	—	(7)	—	(20)	—	(27)	—	27	—
Decrease in finance lease receivable	—	—	11	—	—	—	11	—	(11)	—
Finance lease income	—	—	6	—	—	—	6	—	(6)	—
Adjusted revenues	84	101	264	230	(6)	(2)	671	(6)	(55)	610
Fuel and purchased power[3]	3	6	110	149	—	(2)	266	—	—	266
Reclassifications and adjustments:										
Australian interest income	—	—	(1)	—	—	—	(1)	—	1	—
Mine depreciation	—	—	—	(11)	—	—	(11)	—	11	—
Coal inventory write-down	—	—	—	(1)	—	—	(1)	—	1	—
Adjusted fuel and purchased power	3	6	109	137	—	(2)	253	—	13	266
Carbon compliance	—	—	14	25	—	—	39	—	—	39
Gross margin	81	95	141	68	(6)	—	379	(6)	(68)	305
OM&A[3]	13	17	46	20	5	29	130	—	—	130
Reclassifications and adjustments:										
Parts and materials write-down	—	—	—	3	—	—	3	—	(3)	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	13	17	46	29	5	29	139	—	(9)	130
Taxes, other than income taxes	1	2	2	1	—	—	6	—	—	6
Net other operating income	—	—	(10)	(8)	—	—	(18)	—	—	(18)
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	9	—	—	9	—	(9)	—
Adjusted net other operating (income) loss	—	—	(10)	1	—	—	(9)	—	(9)	(18)
Adjusted EBITDA[4]	67	76	103	37	(11)	(29)	243			
Equity income										4
Finance lease income										6
Depreciation and amortization										(134)
Asset impairment charges										(28)
Net interest expense										(59)
Foreign exchange loss										(6)
Loss on sale of assets and other										(2)
Loss before income taxes										(32)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) In 2021, $6 million was reclassified from OM&A to fuel and purchased power for station service costs in the Hydro segment.
(4) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Reconciliation of Cash Flow from Operations to FFO and FCF

The table below reconciles our cash flow from operating activities to our FFO and FCF for the three months ended Dec. 31, 2022 and 2021:

Three months ended Dec. 31	2022	2021
Cash flow from operating activities[1]	**351**	54
Change in non-cash operating working capital balances	**64**	148
Cash flow from operations before changes in working capital	**415**	202
Adjustments		
Share of adjusted FFO from joint venture[1]	**1**	6
Decrease in finance lease receivable	**12**	11
Clean energy transition provisions and adjustments[2]	**7**	(6)
Realized (gain) loss on closed exchanged positions	**21**	(27)
Other[3]	**3**	—
FFO[4]	**459**	186
Deduct:		
Sustaining capital[1]	**(67)**	(55)
Productivity capital	**(1)**	(2)
Dividends paid on preferred shares	**(12)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(61)**	(38)
Principal payments on lease liabilities	**(3)**	(2)
FCF[4]	**315**	79
Weighted average number of common shares outstanding in the period	**269**	271
FFO per share[4]	**1.71**	0.69
FCF per share[4]	**1.17**	0.29

(1) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.
(2) 2022 includes amounts related to onerous contracts recognized in 2021. 2021 includes a write-down on parts and material inventory and coal inventory for our coal operations and amounts related to onerous contracts and contract termination penalties.
(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.
(4) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The table below provides a reconciliation of our adjusted EBITDA to our FFO and FCF for the three months ended Dec. 31, 2022 and 2021:

Three months ended Dec. 31	2022	2021
Adjusted EBITDA[1]	**541**	243
Provisions	**20**	(18)
Interest expense	**(49)**	(51)
Current income tax (expense) recovery	**(29)**	2
Realized foreign exchange loss	**(18)**	(4)
Decommissioning and restoration costs settled	**(12)**	(5)
Other non-cash items	**6**	19
FFO[2]	**459**	186
Deduct:		
Sustaining capital[3]	**(67)**	(55)
Productivity capital	**(1)**	(2)
Dividends paid on preferred shares	**(12)**	(10)
Distributions paid to subsidiaries' non-controlling interests	**(61)**	(38)
Principal payments on lease liabilities	**(3)**	(2)
FCF[2]	**315**	79

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.
(2) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.
(3) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.

Reconciliation of Non-IFRS Measures on a Consolidated Basis by Segment

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the year ended Dec. 31, 2022:

Year ended, Dec. 31, 2022	Hydro	Wind & Solar(1)	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments(1)	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)	—	2,976
Reclassifications and adjustments:										
Unrealized mark-to-market loss	1	104	251	10	12	—	378	—	(378)	—
Realized (gain) loss on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	607	407	1,521	724	218	(2)	3,475	(14)	(485)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	585	375	801	159	218	—	2,138	(14)	(489)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating (income) loss	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating (income) loss	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA(2)	527	311	629	86	183	(102)	1,634			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Net interest expense										(262)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the year ended Dec. 31, 2021:

Year ended, Dec. 31, 2021	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	383	323	1,109	709	211	4	2,739	(18)	—	2,721
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	25	(40)	19	(38)	—	(34)	—	34	—
Realized (gain) loss on closed exchange positions[2]	—	—	(6)	—	29	—	23	—	(23)	—
Decrease in finance lease receivable	—	—	41	—	—	—	41	—	(41)	—
Finance lease income	—	—	25	—	—	—	25	—	(25)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	383	348	1,126	728	202	4	2,791	(18)	(52)	2,721
Fuel and purchased power	16	17	457	560	—	4	1,054	—	—	1,054
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(79)	(111)	—	—	(190)	—	190	—
Coal inventory write-down	—	—	—	(17)	—	—	(17)	—	17	—
Adjusted fuel and purchased power	16	17	374	432	—	4	843	—	211	1,054
Carbon compliance	—	—	118	60	—	—	178	—	—	178
Gross margin	367	331	634	236	202	—	1,770	(18)	(263)	1,489
OM&A	42	59	175	117	36	84	513	(2)	—	511
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(26)	—	—	(28)	—	28	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	42	59	173	97	36	84	491	(2)	22	511
Taxes, other than income taxes	3	10	13	6	—	1	33	(1)	—	32
Net other operating loss (income)	—	—	(40)	48	—	—	8	—	—	8
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(48)	—	—	(48)	—	48	—
Adjusted net other operating loss (income)	—	—	(40)	—	—	—	(40)	—	48	8
Adjusted EBITDA[3]	322	262	488	133	166	(85)	1,286			
Equity income										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment charges										(648)
Net interest expense										(245)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

The following table reflects adjusted EBITDA by segment and provides reconciliation to earnings (loss) before income taxes for the year ended Dec. 31, 2020:

Year ended, Dec. 31, 2020	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	152	332	787	704	122	7	2,104	(3)	—	2,101
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	2	33	(14)	21	—	42	—	(42)	—
Realized gain on closed exchange positions[2]	—	—	—	—	(10)	—	(10)	—	10	—
Decrease in finance lease receivable	—	—	17	—	—	—	17	—	(17)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Unrealized foreign exchange loss on commodity	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	152	334	848	690	133	7	2,164	(3)	(60)	2,101
Fuel and purchased power	8	25	325	435	—	12	805	—	—	805
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(100)	(46)	—	—	(146)	—	146	—
Coal inventory write-down	—	—	—	(37)	—	—	(37)	—	37	—
Adjusted fuel and purchased power	8	25	221	352	—	12	618	—	187	805
Carbon compliance	—	—	120	48	—	(5)	163	—	—	163
Gross margin	144	309	507	290	133	—	1,383	(3)	(247)	1,133
OM&A	37	53	166	106	30	80	472	—	—	472
Taxes, other than income taxes	2	8	13	9	—	1	33	—	—	33
Net other operating income	—	—	(11)	—	—	—	(11)	—	—	(11)
Reclassifications and adjustments:										
Impact of Sheerness going off-coal	—	—	(28)	—	—	—	(28)	—	28	—
Adjusted net other operating income	—	—	(39)	—	—	—	(39)	—	28	(11)
Adjusted EBITDA[3]	105	248	367	175	103	(81)	917			
Equity income										1
Finance lease income										7
Depreciation and amortization										(654)
Asset impairment charges										(84)
Net interest expense										(238)
Foreign exchange gain										17
Gain on sale of assets and other										9
Loss before income taxes										(303)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

Reconciliation of Cash Flow from Operations to FFO and FCF

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

Year ended Dec. 31	2022	2021	2020
Cash flow from operating activities[1]	**877**	1,001	702
Change in non-cash operating working capital balances	**316**	(174)	(89)
Cash flow from operations before changes in working capital	**1,193**	827	613
Adjustments			
Share of adjusted FFO from joint venture[1]	**8**	13	3
Decrease in finance lease receivable	**46**	41	17
Clean energy transition provisions and adjustments[2][3]	**42**	79	37
Realized (gain) loss on closed positions with same counterparty	**37**	23	(10)
Other[4]	**20**	11	15
FFO[5]	**1,346**	994	675
Deduct:			
Sustaining capital[1]	**(142)**	(199)	(157)
Productivity capital	**(4)**	(4)	(4)
Dividends paid on preferred shares	**(43)**	(39)	(39)
Distributions paid to subsidiaries' non-controlling interests	**(187)**	(159)	(102)
Principal payments on lease liabilities	**(9)**	(8)	(25)
FCF[5]	**961**	585	348
Weighted average number of common shares outstanding in the year	**271**	271	275
FFO per share[5]	**4.97**	3.67	2.45
FCF per share[5]	**3.55**	2.16	1.27

(1) Includes our share of amounts for Skookumchuck, an equity accounted joint venture.
(2) 2021 includes a write-down on parts and material inventory and coal inventory for our coal operations and amounts related to onerous contracts and contract termination penalties. 2020 includes a write-down on coal inventory for our coal operations.
(3) During the third quarter of 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million to the Highvale mine pension plan. 2022 also includes amounts related to onerous contracts recognized in 2021.
(4) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.
(5) These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.

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

Year ended Dec. 31	2022	2021	2020
Adjusted EBITDA(1)	**1,634**	1,286	917
Provisions	**25**	(43)	7
Interest expense	**(200)**	(200)	(192)
Current income tax expense	**(65)**	(56)	(35)
Realized foreign exchange gain (loss)	**—**	(2)	8
Decommissioning and restoration costs settled	**(35)**	(18)	(18)
Other cash and non-cash items	**(13)**	27	(12)
FFO(2)	**1,346**	994	675
Deduct:			
Sustaining capital(3)	**(142)**	(199)	(157)
Productivity capital	**(4)**	(4)	(4)
Dividends paid on preferred shares	**(43)**	(39)	(39)
Distributions paid to subsidiaries' non-controlling interests	**(187)**	(159)	(102)
Principal payments on lease liabilities	**(9)**	(8)	(25)
FCF(2)	**961**	585	348

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.
(2) These items are not defined and have no standardized meaning under IFRS. FFO and FCF are defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to cash flow from operating activities above.
(3) Includes our share of amounts for Skookumchuck wind facility, an equity accounted joint venture.

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

FCF increased by $376 million in 2022, compared to 2021, driven primarily by higher adjusted EBITDA and a decrease in sustaining capital spending due to lower planned maintenance, partially offset by higher distributions paid to subsidiaries' non-controlling interests.

Financial Highlights on a Proportional Basis of TransAlta Renewables

The proportionate financial information below reflects TransAlta's share of TransAlta Renewables relative to TransAlta's total consolidated figures. The financial highlights presented on a proportional basis of TransAlta Renewables are supplementary financial measures to reflect TransAlta Renewables' portion of the consolidated figures.

Consolidated Results for the Year Ended Dec. 31

The following table reflects the generation and summary financial information on a consolidated basis for the year ended Dec. 31:

	Actual generation (GWh)			Adjusted EBITDA[1]			Earnings (loss) before income taxes[2]		
Year ended, Dec. 31	2022	2021	2020	2022	2021	2020	2022	2021	2020
TransAlta Renewables									
Hydro	**410**	434	429	**13**	17	21			
Wind and Solar[3]	**4,248**	3,898	4,042	**273**	248	256			
Gas[3]	**3,308**	3,236	2,919	**223**	217	205			
Corporate	**—**	—	—	**(22)**	(19)	(20)			
TransAlta Renewables before adjustments	**7,966**	7,568	7,390	**487**	463	462	**57**	133	188
Less: Proportion of TransAlta Renewables not owned by TransAlta Corporation	**(3,178)**	(3,020)	(2,938)	**(194)**	(185)	(182)	**(23)**	(53)	(74)
Portion of TransAlta Renewables owned by TransAlta Corporation	**4,788**	4,548	4,452	**293**	278	280	**34**	80	114
Add: TransAlta Corporation's owned assets excluding TransAlta Renewables									
Hydro	**1,578**	1,502	1,703	**514**	305	84			
Wind and Solar	**—**	—	27	**38**	14	(8)			
Gas	**8,140**	7,329	7,861	**406**	271	162			
Energy Transition	**3,574**	5,706	7,999	**86**	133	175			
Energy Marketing	**—**	—	—	**183**	166	103			
Corporate	**—**	—	—	**(80)**	(66)	(61)			
TransAlta Corporation with proportionate share of TransAlta Renewables	**18,080**	19,085	22,042	**1,440**	1,101	735	**330**	(433)	(377)
Non-controlling interests	**3,178**	3,020	2,938	**194**	185	182	**23**	53	74
TransAlta consolidated	**21,258**	22,105	24,980	**1,634**	1,286	917	**353**	(380)	(303)

(1) Adjusted EBITDA is defined in the Additional IFRS Measures and Non-IFRS Measures section of this MD&A and reconciled to earnings (loss) before income taxes above.
(2) TransAlta Renewables amounts are comprised of its reported earnings before income taxes plus the reported earnings before income taxes of the assets in which it holds an economic interest less finance income related to subsidiaries of TransAlta.
(3) Wind and Solar and Gas segments include those assets in which TransAlta Renewables holds an economic interest.

Key Non-IFRS 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 2022.

Adjusted Net Debt to Adjusted EBITDA

As at Dec. 31	2022	2021	2020
Period-end long-term debt(1)	**3,653**	3,267	3,361
Exchangeable securities	**339**	335	330
Less: Cash and cash equivalents(2)	**(1,118)**	(947)	(703)
Add: 50 per cent of issued preferred shares and exchangeable preferred shares(3)	**671**	671	671
Other(4)	**(20)**	(19)	(13)
Adjusted net debt(5)	**3,525**	3,307	3,646
Adjusted EBITDA(6)	**1,634**	1,286	917
Adjusted net debt to adjusted EBITDA(times)	**2.2**	2.6	4.0

(1) Consists of current and long-term portion of debt, which includes lease liabilities and tax equity financing.
(2) Cash and cash equivalents, net of bank overdraft.
(3) Exchangeable preferred shares are considered equity with dividend payments for credit-rating purposes. For accounting purposes, they are accounted for as debt with interest expense in the consolidated financial statements. For purposes of this ratio, we consider 50 per cent of issued preferred shares, including these, as debt.
(4) Includes principal portion of TransAlta OCP restricted cash ($17 million for both 2022 and 2021, $10 million for 2020) and fair value of hedging instruments on debt (included in risk management assets and/or liabilities on the Consolidated Statements of Financial Position).
(5) The tax equity financing for the Skookumchuck wind facility, an equity accounted joint venture, is not represented in this amount. Adjusted net debt is not defined and has no standardized meaning under IFRS. Presenting this item from period to period provides management and investors with the ability to evaluate earnings trends more readily in comparison with prior periods' results. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(6) Last 12 months.

The Company's capital is managed internally and evaluated by management using a net debt position. We use the adjusted net debt to adjusted EBITDA ratio as a measurement of financial leverage and to assess our ability to service debt. Our target for adjusted net debt to adjusted EBITDA is 3.0 to 3.5 times. Our adjusted net debt to adjusted EBITDA ratio for 2022 was better than the low end of our target and improved compared to 2021, as strong adjusted EBITDA more than offset the impact of higher adjusted net debt.

Deconsolidated Adjusted EBITDA by Segment

We invest in our assets directly as well as with joint venture partners. Deconsolidated financial information is a supplementary financial measure and is not intended to be presented in accordance with IFRS.

Adjusted EBITDA is a key metric for TransAlta and TransAlta Renewables and provides management and shareholders a representation of core business profitability. Deconsolidated adjusted 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 adjusted EBITDA to deconsolidated adjusted EBITDA by segment results is set out below:

Year ended Dec. 31	2022			2021			2020		
	TransAlta Consolidated	**TransAlta Renewables**	**TransAlta Deconsolidated**	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Hydro	**527**	**13**		322	17		105	21	
Wind and Solar	**311**	**273**		262	248		248	256	
Gas	**629**	**223**		488	217		367	205	
Energy Transition	**86**	**—**		133	—		175	—	
Energy Marketing	**183**	**—**		166	—		103	—	
Corporate	**(102)**	**(22)**		(85)	(19)		(81)	(20)	
Adjusted EBITDA	**1,634**	**487**	**1,147**	1,286	463	823	917	462	455
Less: TA Cogen adjusted EBITDA			**(197)**			(133)			(54)
Less: EBITDA from joint venture investments[1]			**—**			—			(3)
Add: Dividend from TransAlta Renewables			**151**			151			151
Add: Dividend from TA Cogen			**52**			34			17
Deconsolidated TransAlta adjusted EBITDA			**1,153**			875			566

(1) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

Deconsolidated FFO

The Company has set capital allocation targets based on deconsolidated FFO available to shareholders. Deconsolidated financial information is a supplementary financial measure and is not defined, has no standardized meaning under IFRS and may not be comparable to those used by other entities or by rating agencies. See also the Additional 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:

Year ended Dec. 31	2022			2021			2020		
	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated	TransAlta Consolidated	TransAlta Renewables	TransAlta Deconsolidated
Cash flow from operating activities	**877**	**257**		1,001	336		702	267	
Change in non-cash operating working capital balances	**316**	**(5)**		(174)	(13)		(89)	31	
Cash flow from operations before changes in working capital	**1,193**	**252**		827	323		613	298	
Adjustments:									
Decrease in finance lease receivable	**46**	**—**		41	—		17	—	
Clean energy transition provisions and adjustments(1)	**42**	**—**		79	—		37	—	
Share of FFO from joint venture	**8**	**—**		13	—		3	—	
Realized (gain) loss on closed exchange positions	**37**	**—**		23	—		(10)	—	
Finance income - economic interests	**—**	**(40)**		—	(108)		—	(69)	
FFO - economic interests(2)	**—**	**182**		—	191		—	180	
Other(3)	**20**	**—**		11	—		15	—	
FFO	**1,346**	**394**	**952**	994	406	588	675	409	266
Dividend from TransAlta Renewables			**151**			151			151
Distributions to TA Cogen's Partner			**(87)**			(56)			(17)
Less: Share of adjusted FFO from joint venture(4)			**—**			—			(3)
Deconsolidated TransAlta FFO			**1,016**			683			397

(1) During the third quarter of 2022, to support the employees affected by the closure of the Highvale mine and our transition off coal to cleaner sources, the Company made a voluntary special contribution of $35 million to the Highvale mine pension plan. 2022 also includes amounts related to onerous contracts recognized in 2021. 2021 includes a write-down on parts and material inventory and coal inventory for our coal operations and amounts related to onerous contracts and contract termination penalties. 2020 includes a write-down on coal inventory for our coal operations.
(2) FFO - economic interests calculated as FCF economic interests plus sustaining capital expenditures economic interests and tax equity distributions, and plus/minus currency adjustment.
(3) Other consists of production tax credits, which is a reduction to tax equity debt, less distributions from equity accounted joint venture.
(4) As of the second quarter of 2021, our share of amounts for the Skookumchuck wind equity accounted joint venture is excluded from the TransAlta deconsolidated results due to the sale of an economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables.

Deconsolidated Net Debt to Deconsolidated Adjusted EBITDA

In addition to reviewing fully consolidated ratios and results, management reviews net debt to adjusted EBITDA on a deconsolidated basis to highlight TransAlta's financial flexibility, balance sheet strength and leverage. Deconsolidated financial information is a supplementary financial measure and is not defined under IFRS, and may not be comparable to measures used by other entities or by rating agencies. Also, refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further details.

As at Dec. 31	2022	2021	2020
Adjusted net debt(1)	**3,525**	3,307	3,646
Add: TransAlta Renewables cash and cash equivalents(2)	**234**	244	582
Less: TransAlta Renewables long-term debt	**(790)**	(814)	(692)
Less: US tax equity financing and South Hedland debt(3)	**(834)**	(867)	(906)
Deconsolidated net debt	**2,135**	1,870	2,630
Deconsolidated adjusted EBITDA(4)(5)	**1,153**	875	566
Deconsolidated net debt to deconsolidated adjusted EBITDA(6) (times)	**1.9**	2.1	4.6

(1) Adjusted net debt is a Non-IFRS measure. Refer to the Adjusted Net Debt to Adjusted EBITDA calculation under the Key Financial Non-IFRS Financial Ratios section of this MD&A for the reconciliation and composition of adjusted net debt.
(2) In 2022, includes cash held within TransAlta Energy (Australia) Pty Ltd. reserved for future funding of Australian growth projects by TransAlta Renewables.
(3) Relates to assets where TransAlta Renewables has economic interests.
(4) Refer to the Deconsolidated Adjusted EBITDA by Segment section of this MD&A for the reconciliation and composition of deconsolidated adjusted EBITDA and the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for the composition of adjusted EBITDA.
(5) Last 12 months.
(6) The non-IFRS ratio is not a standardized financial measure under IFRS and might not be comparable to similar financial measures disclosed by other issuers.

Our target for deconsolidated net debt to deconsolidated adjusted EBITDA is 2.5 to 3.0 times. Our deconsolidated net debt to deconsolidated adjusted EBITDA ratio for 2022 improved compared with 2021, as higher deconsolidated adjusted EBITDA more than offset the increase in deconsolidated net debt. Higher deconsolidated net debt is a result of higher corporate debt, partially offset by an increase in cash balances.

2023 Outlook

Our annual outlook highlights continuing strong cash flow expectations for 2023. Our fleet remains well positioned to capture the ongoing strength that we see in the Alberta merchant market. The Company is focused on redeploying these cash flows towards growing our contracted renewables asset base. On Nov. 7, 2022, the Board of Directors approved an increase to the annualized dividend to $0.22 per share, beginning with the Jan. 1, 2023 dividend.

The following table outlines our expectations on key financial targets and related assumptions for 2023 and should be read in conjunction with the narrative discussion that follows and the Governance and Risk Management section of this MD&A:

Measure	2023 Target	2022 Updated target	2022 Actuals
Adjusted EBITDA(1)(2)	$1,200 million-$1,320 million	$1,380 million-$1,460 million	$1,634 million
FCF(1)(2)	$560 million-$660 million	$725 million-$775 million	$961 million
Dividend	$0.22 per share annualized	$0.20 per share annualized	$0.20 per share annualized

(1) These items are not defined and have no standardized meaning under IFRS. Refer to the Reconciliation of Non-IFRS Measures section of this MD&A for further discussion of these items, including, where applicable, reconciliations to measures calculated in accordance with IFRS. See also the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(2) During the third quarter of 2022, the Company revised and increased our 2022 guidance for adjusted EBITDA and FCF based on the strong financial performance attained to date and our expectations for the balance of year.

Range of key 2023 power and gas price assumptions

Market	2023 Assumption
Alberta Spot ($/MWh)	$105 to $135
Mid-C Spot (US$/MWh)	US$75 to US$85
AECO Gas Price ($/GJ)	$4.60

Alberta spot price sensitivity: a +/- $1/MWh change in spot price is expected to have a +/- $4 million impact on adjusted EBITDA for 2023.

Other assumptions relevant to the 2023 outlook	
Sustaining capital	$140 million - $170 million
Energy Marketing gross margin	$90 million - $110 million

Alberta Hedging

Range of hedging assumptions	2023(1)
Hedged production (GWh)	6,874
Hedge price ($/MWh)	$98
Hedged gas volumes (GJ)	64 million
Hedge gas prices ($/GJ)	$2.54

(1) In the fourth quarter of 2022, the Company revised the range of hedging assumptions for 2023 based on current hedge levels.

Adjusted EBITDA is estimated to be between $1.2 billion and $1.3 billion. The midpoint of the range represents an 11 per cent decrease from the midpoint of the 2022 outlook. FCF is expected to be between $560 million and $660 million and excludes the impact of the rehabilitation capital expenditures required at Kent Hills 1 and 2 wind facilities. The midpoint of the range represents a 19 per cent decrease from the midpoint of the 2022 outlook. These changes to adjusted EBITDA and FCF are largely driven by lower expected pricing levels in Alberta based on our fundamental forecast and adjusted performance expectations from the Energy Marketing segment, partially offset by contributions from newly commissioned projects that will include the Garden Plain wind project, White Rock wind projects, Horizon Hill wind projects, Northern Goldfields solar project, Mount Keith 132kV transmission expansion and completion of the Kent Hills 1 and 2 rehabilitation and the full return of the wind facilities to service in the second half of 2023.

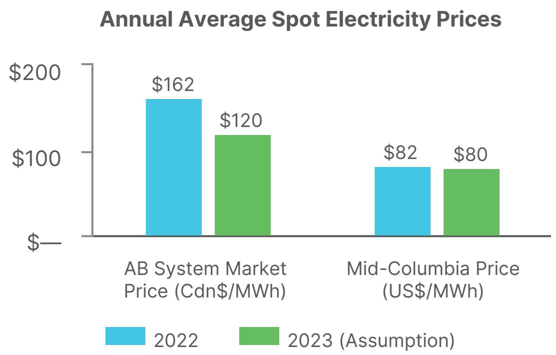
The Company's outlook for 2023 may be impacted by a number of factors as detailed further below.

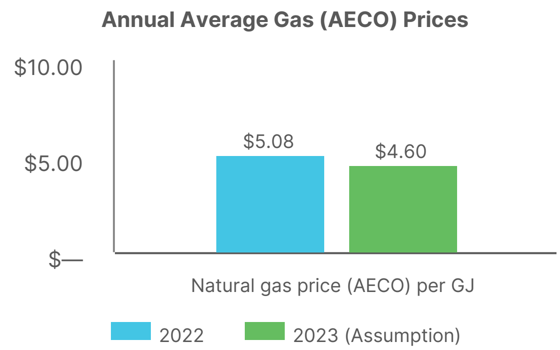
Operations

The following provides an update to our assumptions included in the 2023 Outlook.

Market Pricing

The following graphs include 2023 pricing based on a range of assumptions and is subject to change:





For 2023, we see strong merchant pricing levels continuing in Alberta and the Pacific Northwest, although at lowered target ranges for both regions. Lower year-over-year pricing in Alberta is expected to be driven by normalized weather expectations and the expected additions of new gas, wind and solar supply, including TransAlta's new Garden Plain wind facility, which is expected to achieve commercial operation in the first half of 2023. Lower year-over-year pricing in the Pacific Northwest will be impacted by weaker natural gas prices and will also depend on the actual hydrology for the region during the year. Ontario power prices for 2023 are expected to be lower than 2022 due to lower natural gas prices despite ongoing nuclear refurbishment outages.

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 assets within the Alberta Electricity Portfolio 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.

Kent Hills Wind Facilities Outage

It is expected that the rehabilitation of the Kent Hills 1 and 2 wind facilities will be completed and they will fully return to service in the second half of 2023.

Fuel and Compliance Costs

For the Alberta Gas fleet, gas consumption is expected to decrease from lower generation. This 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. This will be partially offset by an increased carbon tax in Alberta.

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 from external suppliers in the Powder River Basin and delivered by rail. The delivered fuel cost in 2023 is expected to be higher than 2022 due to higher expected generation.

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 in line 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

Adjusted EBITDA from our Energy Marketing segment is affected by prices and volatility in the market, overall strategies adopted and changes in regulation and legislation. Our outlook has been adjusted to reflect the exceptional performance achieved in 2021 and 2022. We continuously monitor both the market and our exposure to maximize earnings while still maintaining an acceptable risk profile. Our 2023 objective for the Energy Marketing segment is to contribute between $90 million and $110 million in realized gross margin for the year, which is consistent with normalized performance expectations.

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 principal and interest charges, which largely offset our net foreign-denominated revenues.

Decommissioning and Restoration Costs

Decommissioning and restoration costs are expected to be higher in 2023, largely driven by increases in restoration costs associated with the retired Alberta assets within the Energy Transition segment.

Sustaining Capital Expenditures

The Company expects sustaining capital to be in the range of $140 million to $170 million. The midpoint for the range represents a 3 per cent decrease from the midpoint of the 2022 outlook sustaining capital range of $150 million to $170 million. This is driven by lower sustaining capital expenditures for planned major maintenance related to the Centralia Unit 2 and the Sheerness facility offset by higher capital expenditure across our Hydro fleet.

The Kent Hills foundation rehabilitation capital expenditure has been segregated from our sustaining capital range due to the extraordinary and rare nature of this expenditure. Refer to the Wind and Solar section of this MD&A for more details.

Our estimate for total sustaining capital is as follows:

	Spent in 2022	Spent in 2021	Expected spend in 2023
Total sustaining capital	**142**	199	140-170

Liquidity and Capital Resources

We expect to maintain adequate available liquidity under our committed credit facilities, including the Term Facility (as defined above), which the Company entered into during the third quarter of 2022. We currently have access to $2.1 billion in liquidity, including $1.1 billion in cash. On Nov. 17, 2022, the Company issued US$400 million Senior Green Bonds, which have a coupon rate of 7.75 per cent per annum and mature on Nov. 15, 2029. Including the effects of settled interest rate swaps, the notes have an effective yield of approximately 5.98 per cent. The funds required for committed growth, sustaining capital and productivity projects are not expected to be significantly impacted by the current economic environment. Refer to the Significant and Subsequent Events and Financial Capital sections of this MD&A for further details.

Net Interest Expense

Interest expense for 2023 is expected to be slightly higher than in 2022, largely due to higher levels of debt, partially offset by higher capitalized interest on growth project expenditures. 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.

Strategy and Capability to Deliver Results

Our goal is to be a leading customer-centred electricity company, committed to a sustainable future, focused on increasing shareholder value by growing our portfolio of high-quality generation facilities with stable and predictable cash flows. Our strategy includes meeting our customers' needs for clean, safe, low-cost, reliable electricity and providing operational excellence and continuous improvement in everything we do.

The Company's enhanced focus on renewable generation and storage solutions for customers is driven largely by global decarbonization policies and the increase in demand and growth projections in the renewable sector, namely for companies to achieve their ESG ambitions. For additional information on regulatory developments, refer to the ESG section of this MD&A.

On Sept. 28, 2021, TransAlta announced its strategic growth targets and a five-year Clean Electricity Growth Plan. Our Clean Electricity Growth Plan established the following strategic priorities and targets to guide our path from 2021 to 2025. These include:

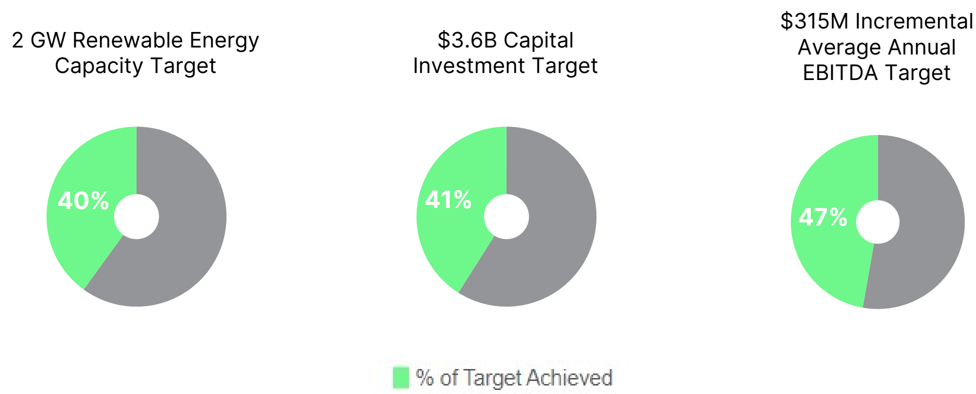
- Deliver 2 GW of incremental renewable capacity with a targeted capital investment of $3.6 billion[1] by the end of 2025. These new assets, once fully operational, are targeted to deliver incremental average annual EBITDA[2] of $315 million[1];
- Accelerate growth into customer-centred renewables and storage through the deployment of our 3 GW development pipeline;
- Expand the Company's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet between 2025 and 2030;
- Realize targeted diversification and value creation by focusing on expanding our platform in each of our core geographies (Canada, the US and Australia);
- Lead in ESG policy development to enable the successful evolution of the markets in which we operate and compete; and
- Define the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025.

Our 2023 priorities for the Clean Electricity Growth Plan include:

- Reaching final investment decision on 500 MW of additional clean energy projects across Canada, the US and Australia; and
- Adding at least 1,500 MW of new development sites to our pipeline.

We expect the Company's adjusted EBITDA generated from renewable sources, including hydro, wind and solar technologies, to increase to 70 per cent by the end of 2025. The Clean Electricity Growth Plan will largely be funded from current cash balances, cash generated from operations and asset-level financing.

As of Feb. 22, 2023, we have made significant progress in achieving the targets of the Clean Electricity Growth Plan.



1 The targeted capital investment of $3 billion and average annual EBITDA of $250 million, as previously disclosed in 2021, were revised upwards for the current inflationary environment.

2 Average annual EBITDA is not defined and has no standardized meaning under IFRS, and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

Our progress towards achieving our strategic targets is summarized below:

Strategic Targets

Goals	Target	Results	Comments
Accelerate Growth in Customer-centered Renewables and Storage	Deliver 2 GW of renewable capacity with an estimated capital investment of $3.6 billion[1] by the end of 2025.	On track	In 2022, the Company delivered two new projects. The 200 MW Horizon Hill wind project and the Mount Keith 132kV transmission expansion in Australia. Construction on these new projects commenced in 2022 and they are both planned for completion in the second half of 2023. As of the end of 2022, we have successfully delivered 800MW of new growth, 40% of our 2 GW target.
	Deliver incremental average annual EBITDA of $315 million.[1]	On track	The Horizon Hill wind project will add incremental EBITDA in the range of US$30-US$33 million and the Mount Keith 132kV transmission expansion will add incremental EBITDA in the range of AU$6-AU$7 million. Our cumulative progress towards our incremental EBITDA target is approximately $149 million.
	Expand the Company's development pipeline to 5 GW by 2025 to enable a two-fold increase in its renewables fleet between 2025 and 2030.	On track	The Company continues to evaluate opportunities to add new development sites to our pipeline. These include acquisitions of individual early-stage development sites, small development portfolios and prospecting of new sites. For 2022, we have grown our development pipeline by approximately 1,980 MW in the US, Canada and Australia.
Take a Targeted Approach to Diversification	Grow our asset base in our core geographies of Canada, Australia and the US to realize diversification and value creation.	On track	The Company has successfully added new contracted renewable assets in each of its three core geographies. We have diversified within the US market through our North Carolina Solar facility acquisition In 2021 and the new Oklahoma investments, which added three new investment-grade customers in 2022.
Maintain Our Financial Strength and Capital Allocation Discipline	Deliver strong cash flow from our existing portfolio to allocate towards our funding priorities including growth, dividends and share buybacks.	On track	The Company had liquidity of $2.1 billion as at Dec. 31, 2022. The Company returned $54 million to shareholders through share buybacks in 2022 under our NCIB. The Company increased the annual common share dividend by 10 per cent to $0.22 per year effective Jan. 1, 2023.
Define the Next Generation of Energy Solutions and Technologies	Meet the needs of our customers and communities through the implementation of innovative energy solutions and parallel investments in new complementary sectors by the end of 2025.	On track	The Company established an Energy Innovation team to progress our goals in this area. The team has recently completed an equity investment in Ekona Power Inc., an early-stage hydrogen production company, in order to pursue commercialization of low cost, net-zero aligned hydrogen. The Company also committed to invest US$25 million over the next four years in the Energy Impact Partners Frontier Fund, which provides a portfolio approach to investing in emerging technologies focused on net-zero emissions. In 2022, the Company invested $10 million (US$8 million).
Lead in ESG Policy Development	Actively participate in policy development to ensure the electricity that we provide contributes to emissions reduction, grid reliability and competitive energy prices to enable the successful evolution of the markets in which we operate and compete.	On track	The Company is actively engaging the Government of Canada and Government of Alberta regarding the proposed federal Clean Electricity Regulations. Throughout the engagement, TransAlta continues to provide input regarding how to achieve emissions reductions while maintaining necessary reliability and affordability. The Company worked with the Government of Canada as the government designed new investment tax credits for clean technologies.
Successfully Navigate through the COVID-19 Pandemic	Continue to maintain an effective response to COVID-19 and plan a safe return to our offices.	Achieved	Our staff have returned to our offices and sites, and we continue to monitor local public health authority and government guidelines in all jurisdictions in which we operate to ensure the ongoing health and safety of all employees and contractors.

(1) The targeted capital investment of $3 billion and average annual EBITDA of $250 million, as previously disclosed in 2021, were revised upwards for the current inflationary environment.

Growth

The Company announced two new projects in 2022: the 200 MW Horizon Hill wind project and the Mount Keith 132kV expansion project. We have established, and are continuing to expand, our pipeline of potential growth projects. Our pipeline includes 374 MW of advanced-stage development projects along with 3,891 MW to 4,991 MW of projects in earlier stages of development.

We are primarily evaluating greenfield opportunities in Alberta, Western Australia and the US along with acquisitions in markets in which we have existing operations.

Projects under Construction

The following projects have been approved by the Board of Directors, have executed PPAs and are currently under construction. The projects under construction will be financed through existing liquidity in the near term. We will continue to explore project financing or tax equity as a long-term financing solution on an asset-by-asset basis.

				Total project (millions)					
Project	Type	Region	MW	Estimated spend	Spent to date	Target completion date(1)	PPA Term (2)	Average annual EBITDA(3)	Status
Canada									
Garden Plain(4)	Wind	AB	130	$ 190 — $200	$ 171	H1 2023	17	$14-$15	• Fully contracted • All major equipment deliveries are complete • Turbine erection and commissioning is now underway • Grid interconnection completed
United States									
White Rock(5)	Wind	OK	300	US$ 470 — US$490	US$273	H2 2023	—	US$48-US$52	• Long-term PPAs executed • Wind turbine component deliveries in progress • Construction activities have commenced • On track to be completed on schedule
Horizon Hill (5)	Wind	OK	200	US$ 300 — US$315	US$141	H2 2023	—	US$30-US$33	• Long-term PPA executed • Wind turbine component deliveries in progress • Construction activities have commenced • On track to be completed on schedule
Australia									
Northern Goldfields	Hybrid Solar	WA	48	AU$ 69 — AU$73	AU$59	H1 2023	16	AU$9-AU$10	• All major equipment deliveries are complete • Solar panel installation is complete • On track to be completed in early 2023
Mount Keith 132kV Expansion	Transmission	WA	n/a	AU$ 50 — AU$53	AU$17	H2 2023	15	AU$6-AU$7	• Engineering, procurement, and construction executed • Construction activities have commenced • On track to be completed on schedule

(1) H1 or H2 is defined as the first or second half of the year.
(2) The PPA term is confidential for the White Rock wind projects and Horizon Hill wind project.
(3) This item is not defined and has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.
(4) The Garden Plain wind project is fully contracted, with Pembina off-taking 100 MW of the total 130 MW capacity of the facility and the remaining 30 MW contracted to an investment-grade globally recognized customer. Refer to the Significant and Subsequent Events section of this MD&A for further details.
(5) The expected average annual EBITDA and estimated capital spending for the White Rock wind projects and Horizon Hill wind projects have been revised upwards based on the impact of the Inflation Reduction Act of 2022, which results in the projects qualifying for 100 per cent production tax credits, partially offset by incremental payments to the turbine supplier.

Advanced-Stage Development

These projects have detailed engineering, advanced position in the interconnection queue and are progressing offtake opportunities. The following table shows the pipeline of future growth projects currently under advanced-stage development:

Project	Type	Region	Gross installed capacity (MW)	Estimated spend	Average annual EBITDA[(1)]
Tempest	Wind	Alberta	100	$210-$230	$20-$23
SCE Capacity Expansion	Gas	Western Australia	94	AU$180-AU$200	AU$24-AU$28
WaterCharger	Battery Storage	Alberta	180	$150-$180	$14-$17
Australia Transmission Expansion	Transmission	Western Australia	n/a	AU$34-AU$36	AU$3-AU$4

(1) This item is not defined, has no standardized meaning under IFRS and is forward-looking. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A for further discussion.

Early-Stage Development

These projects are in the early stages and may or may not move ahead. Generally, these projects will have:

- Collected meteorological data;
- Begun securing land control;
- Started environmental studies;
- Confirmed appropriate access to transmission; and
- Started preliminary permitting and other regulatory approval processes.

The following table shows the pipeline of future growth projects currently under early-stage development:

Project	Type	Region		Gross installed capacity (MW)
Canada				
Riplinger Wind	Wind	Alberta		300
Red Rock	Wind	Alberta		100
Willow Creek 1	Wind	Alberta		70
Willow Creek 2	Wind	Alberta		70
Sunhills Solar	Solar	Alberta		115
McNeil Solar	Solar	Alberta		57
Canadian Battery opportunity	Battery	New Brunswick		10
Canadian Wind opportunities	Wind	Various		370
Tent Mountain Pumped Storage	Hydro	Alberta		160
Brazeau Pumped Hydro	Hydro	Alberta		300-900
Alberta Thermal Redevelopment	Various	Alberta		250-500
			Total	**1,802-2,652**
United States				
Old Town	Wind	Illinois		185
Trapper Valley	Wind	Wyoming		225
Monument Road	Wind	Nebraska		152
Dos Rios	Wind	Oklahoma		242
Prairie Violet	Wind	Illinois		130
Big Timber	Wind	Pennsylvania		50
Oklahoma Solar	Solar	Oklahoma		100
Milligan 3	Wind	Nebraska		126
Other Wind and Solar prospects	Wind and Solar	Various		409
Centralia site redevelopment	Various	Washington		250-500
			Total	**1,869-2,119**
Australia				
Australian prospects	Gas, Solar, Wind	Western Australia		170
South Hedland Solar	Solar	Western Australia		50
			Total	**220**
Canada, United States and Australia			**Total**	**3,891-4,991**

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 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 (loss), while any ineffective portion is recognized in net earnings (loss).

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 (loss) 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 or loss ("OCI"). These gains or losses are subsequently reclassified from OCI to net earnings (loss) in the same period as the hedged forecast cash flows impact net earnings (loss) 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 that 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 (loss) 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 (loss) 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, 2022, Level III instruments had a net liabilities carrying value of $782 million (2021 – net asset $159 million). Our risk management profile and practices have not changed materially from Dec. 31, 2021. Refer to the Material Accounting Policies and Critical Accounting Estimates section of this MD&A for further details regarding valuation techniques.

Material Accounting Policies and Critical Accounting 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 material accounting policies are described in Note 2 of the consolidated financial statements. 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. Estimates to the extent to which geopolitical events such as the Russia-Ukraine conflict or inflationary and supply chain dynamics may, directly or indirectly, impact the Company's operations, financial results and conditions in future periods are also subject to significant uncertainty. Uncertainty related to COVID-19 and the geopolitical events has been considered in our estimates for the year ended Dec. 31, 2022.

We have discussed the development and selection of these critical accounting estimates with the Audit, Finance and Risk Committee ("AFRC") of the Board of Directors 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

Identification of Performance Obligations
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
In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage and capacity requirements when estimating the goods and services to be provided to the customer. The Company 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 Company expects to be entitled to in exchange for transferring the good or service.

The Company’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 Company 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.

Revenue from Other Sources

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 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 other models such as numerical derivative valuation or scenario analysis.

Merchant Revenue
Revenues from non-contracted capacity (i.e., merchant) are comprised of energy payments, at market price, for each MWh produced and are recognized upon delivery.

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 are utilized by the Company. 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. Refer to Note 14(B)(I) and (II) from our consolidated financial statements for further details on the inputs used for each level.

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, 2022, is an estimated total upside of $193 million (2021 – $105 million) and total downside of $287 million (2021 – $220 million) impact to the carrying value of the financial instruments. The amount of $15 million upside (2021 – $22 million) and $163 million downside (2021 – $145 million) in stress value stems from a power sale contract in Pacific Northwest that is designated as a cash flow hedge. Fair values are stressed for unobservable inputs, which can include variable volumes, unobservable prices and wind discounts, among other inputs. The variable volumes are stressed up and down based on 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. Wind discounts represent price to volume relationships and are stressed specific to each location.

In addition to the Level III fair value measurements discussed above, the Brookfield Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum of 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the option to exchange is considered a Level III fair value measurement, with an estimated downside of $25 million (2021 – $32 million) potential impact to the carrying value of nil as at Dec. 31, 2022 (2021 – nil). The sensitivity analysis has been prepared using the Company's assessment that a change in the implied discount rate of the future cash flow of one per cent is a reasonably possible change.

Valuation of PP&E and Associated Contracts

At the end of each reporting period, we assess whether there is any indication that PP&E and finite life intangible assets are impaired or whether a previously recognized impairment may no longer exist or may have decreased.

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 cash-generating unit ("CGU") to which the asset belongs. 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 recoverable amount is the higher of an asset's fair value less costs of disposal or 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. 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 2022.

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. Refer to the Financial Position section of this MD&A for further details.

Asset Impairments

Hydro
During 2022, the Company recorded net impairment charges of $21 million on four hydro facilities as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows.

Wind and Solar
During 2022, the Company recorded net impairment charges of $43 million on five wind facilities and one solar facility as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows.

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 2022, 2021 and 2020 annual goodwill impairment reviews, the Company determined the recoverable amounts of the CGUs by calculating the fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts for the period extending to the last planned asset retirement in 2072. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. We have determined there were no goodwill impairments for 2022, 2021 and 2020.

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, including 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.

Project Development Costs

Project development costs include external, direct and incremental costs that are necessary for completing an acquisition or construction project. 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 (loss).

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.

Change in Estimate - Useful Lives

During 2022, the Company adjusted the useful lives of certain assets included in the Gas segment to reflect changes made based on the future operating expectations of the assets. This resulted in an increase of $132 million in depreciation expense that was recognized in the Consolidated Statement of Earnings (Loss) in 2022.

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

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. 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.

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.

Defined Benefit Obligation

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has decreased by $78 million to $150 million as at Dec. 31, 2022, from $228 million as at Dec. 31, 2021. The decrease is primarily driven by increases in discount rates in 2022, largely driven by increases in market benchmark rates and the voluntary contribution of $35 million made to the Sunhills Mining Ltd. Pension Plan, partially offset by a decrease in plan assets due to poor market returns.

The Company made a voluntary contribution of $35 million during 2022 to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale mine and to support the employees affected by the closure of the Highvale mine in 2021 and our transition off-coal to cleaner sources. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

A 1 per cent increase in discount rates would have a $39 million impact on the defined benefit obligation.

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.

The Company recognizes provisions for decommissioning obligations. Initial decommissioning provisions and subsequent changes thereto, are determined using the Company’s best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement.

During 2022, the Company accelerated the expected timing on decommissioning and restoration for certain facilities. This increased the decommissioning and restoration provision by $95 million of which $46 million increased operating assets in PP&E and $49 million was recognized as an impairment charge in net earnings related to retired assets.

In 2021, the Company increased the decommissioning and restoration provision $167 million related to an engineering study on the decommissioning costs of the wind sites of $120 million and the Sundance and Keephills Units useful lives of $47 million. Of the total increase in decommissioning and restoration provisions, $133 million increased operating assets in PP&E and $34 million was recognized as an impairment charge in net earnings related to retired assets.

During 2022, the decommissioning and restoration provision decreased by $225 million (2021 – $6 million) due to a significant increase in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 7.0 to 9.7 per cent as at Dec. 31, 2022 (2021 –3.6 to 6.5 per cent). This has resulted in a corresponding decrease in PP&E of $123 million (2021 – $6 million) on operating assets and recognition of a $102 million (2021 – nil) impairment reversal in net earnings related to retired assets.

We estimate the undiscounted amount of cash flow required to settle the decommissioning and restoration provisions is approximately $1.6 billion, which will be incurred between 2023 and 2072. The majority of these costs will be incurred between 2023 and 2050.

Other Provisions

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

Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company 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 Company 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.

Significant Influence

Upon entering into an investment, the Company must classify it as either an investment as an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company 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 Company 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 Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

Accounting Changes

Current Accounting Changes

Amendments to International Accounting Standards ("IAS") 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued Onerous Contracts – Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted on adoption of the amendments on Jan. 1, 2022.

Future Accounting Changes

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the IASB issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, with early application permitted. The Company's current position aligns with the amendment and no financial impact is therefore expected upon adoption on the effective date.

Amendments to IAS 1 Classification of Liabilities as Current or Non-Current

In October 2022, the IASB issued amendments to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability, in addition to the amendment from January 2020 where the IASB issued amendments to IAS 1 Presentation of Financial Statements, to provide a more general approach to the presentation of liabilities as current or non-current based on contractual arrangements in place at the reporting date. These amendments specify that the rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months, provided that management's expectations are not a relevant consideration as to whether the Company will exercise its rights to defer settlement of a liability and clarify when a liability is considered settled.

The amendments are effective for annual periods beginning on or after Jan. 1, 2024, and are to be applied retrospectively. The Company has not yet determined the impact of these amendments on its consolidated financial statements.

Amendments to IFRS 16 Lease Liability in a Sale-and-Leaseback

In September 2022, the IASB issued Lease Liability in a Sale and Leaseback, which amends IFRS 16 Leases to provide additional specifications when subsequently measuring the lease liability that require the seller-lessee to determine lease payments and revised lease payments in a way that does not result in the seller-lessee recognizing any amount of the gain or loss that relates to the right of use it retains. The current effective date is Jan. 1, 2024. The Company is currently reviewing the impacts of this amendment on its consolidated financial statements.

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 (loss).

Environmental, Social and Governance

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.

Our key strategic sustainability pillars build on our corporate strategy and weave through our business. 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:

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

Reporting on Our Material Sustainability Factors

TransAlta has been reporting on sustainability since 1994. The Company's ESG reporting content is integrated within this MD&A to provide information on how ESG affects our business (including material focus areas) and is guided by leading ESG reporting frameworks. We adopt guidance from the International Integrated Reporting Framework, the Global Reporting Initiative and the Sustainability Accounting Standards Board ("SASB") requirements for electric utilities and power generators. We continue to monitor the development of sustainability and climate-related disclosure requirements to assess our future reporting, such as the International Sustainability Standards Board (“ISSB”), the Taskforce on Nature-related Financial Disclosures (“TNFD”), the Canadian Securities Administrators, and the U.S. Securities and Exchange Commission.

Climate-related data to be disclosed is informed by the recommendations of the Task Force on Climate-related Financial Disclosures ("TCFD") and climate change questionnaires from CDP (the global disclosure system for environmental impacts known formerly as the Carbon Disclosure Project). In 2022, we reviewed and updated our management response to our 2021 climate-related scenario analysis that enhanced our alignment with both international sustainability frameworks. We also developed our first consolidated Climate Transition Plan and prepared climate-related financial metrics. GHG emissions data for scopes 1 and 2 follow the accounting and reporting standards of the GHG Protocol. We continue to improve our scope 3 accounting for future reporting in alignment with the GHG Protocol. For further information on climate change management and the findings of our scenario analysis, refer to the Decarbonizing Our Energy Mix section of this MD&A.

The disclosure of our most relevant sustainability factors is guided by our sustainability materiality assessment. In 2022, we refreshed our materiality assessment by evaluating key sector-specific research on material issues, supported by internal and external engagement on key sustainability issues. Our Enterprise Risk Management ("ERM") program is designed to help the organization focus its efforts on key enterprise risks, within the planning horizon, that could significantly impact the success of its strategy, including its sustainability objectives. We consider a sustainability factor as material if it could substantively affect our ability to create value.

In 2022, we reviewed key topics identified within SASB, TCFD, IFRS and TNFD to inform the identification of our material sustainability factors. We also considered sustainability factors from the electricity sector through Electricity Canada’s 2021 Sustainable Electricity Report. In addition, we conducted a peer review of material sustainability factors. This work was validated by our executive team and resulted in the identification of 21 material sustainability factors presented in the Sustainability Governance section of this MD&A.

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

Accelerating Our Business Transformation to Become Net-Zero by 2045

At TransAlta, our mission is to provide safe, low-cost and reliable clean electricity to our customers. As a customer-centred clean electricity leader, we are well positioned to support our customers' ESG and sustainability goals. To achieve this goal, in today's evolving economy and increasingly electrified world, our strategy focuses on renewable electricity growth and a deep commitment to sustainability. We believe that we are uniquely positioned as the world continues to electrify and adopt sustainability practices. For further information, refer to the Description of the Business section of this MD&A.

Our President and Chief Executive Officer, John Kousinioris, speaks about our decarbonization journey below.

TransAlta has adopted a 2045 net-zero target. Why did the company choose to take that step?

"Our new net-zero target is a function of our growth strategy. Simply put, by focusing on growing our contracted renewable assets, we are growing our business and not our emissions. This type of growth, along with our investments in new technologies and ongoing participation in environmental markets, makes us confident that we will be able to reach this new target. We believe it is important for the Company to publicly hold itself accountable for delivering these results and ensuring our investors, customers and stakeholders are aware of where we are going in this important effort."

How does the Company's strategy align with the Paris Agreement goals?

"We are committed to maintaining a leadership position in climate change and contributing to a net-zero future. Our growth strategy focuses on renewable and storage projects, which is in line with the Paris Agreement goal to limit global warming to 1.5°C. On a percentage basis, TransAlta has already achieved emissions reductions beyond the 2030 national targets in our operating jurisdictions and we anticipate further reductions before the end of the decade. Our GHG reduction trajectory is consistent with the Paris Agreement. Our public policy engagement is aligned with TransAlta's climate change commitments, and supports appropriate policy measures to mitigate climate risks."

What technologies will TransAlta adopt to help customers to decarbonize?

"TransAlta helps our customers by delivering and operating reliable renewable and storage projects and on-site generation that meet their needs. Underneath that core commitment is a set of technologies and contracting options that we tailor to ensure customers receive the energy they require and the environmental outcomes that are aligned with their ESG commitments. Since 2021, our Energy Innovation team has been building our expertise in emerging technologies. This work led to a $2 million equity investment in Ekona for commercialization of a methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. We have also committed to investing US$25 million over the next four years in the Energy Impact Partners Frontier Fund 1. This allows us to identify, pilot and commercialize technologies that will support our decarbonization goals. We will continue to make strategic investments moving forward. In doing so, we will strengthen our position as a customer-centric clean electricity partner and mitigate technology risks to our merchant assets."

How can the Company make its energy transition work for people?

"Our energy transition is focused on implementing decarbonization strategies within an inclusive transition framework. For example, since 2015, TransAlta has been investing US$55 million over 10 years to support energy efficiency, economic and community development, education and retraining initiatives in Washington State. In Alberta, since 2016, we have committed to investing in programs and initiatives to support the communities surrounding the plants negatively impacted by the phase-out of coal generation during the transition. We can never understate the difficulty of these transitions for our workers and the communities where our operations are changing. Our goal is to work through the transition and contribute to a positive future where new opportunities emerge."

2023+ Sustainability Targets

Our 2023 and longer-term sustainability targets support the success of our business so that the Company will continue to be positioned as an ESG leader in the future. Goals and targets are established to improve our ESG performance and manage current and emerging material sustainability issues in support of the United Nations Sustainable Development Goals ("UN SDGs") and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. TransAlta is committed to decarbonizing our energy generation and accelerating clean energy growth. We believe that we can make a greater positive impact on UN SDG 7 “Affordable and Clean Energy” and SDG 13 “Climate Action”, while supporting seven other SDGs.

TransAlta has adopted five new sustainability targets in the areas of climate change, biodiversity, safety and supply chain.

We adopted a more stringent climate-related target to achieve net-zero for 100 per cent of TransAlta’s scope 1 and 2 GHG emissions by 2045. In 2021, TransAlta approved a climate-related target to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year. We estimate that this target is in line with the latest climate science and the electricity sector decarbonization pathway to limit global warming to 1.5°C and meet the Paris Agreement goals. We have also committed to verifying and disclosing 80 per cent of our total scope 3 emissions by 2024.

In addition, TransAlta approved two new biodiversity targets that support the intent of the TNFD recommendations.

We also enhanced the target of our Total Recordable Injury Frequency ("TRIF") and a new supply chain target was set to integrate sustainability considerations into our supply chains.

Our targets to reduce air emissions and fleet-wide water consumption were achieved in 2022, four years ahead of the 2026 target date. In 2023, we will review setting new targets for air emissions and water consumption consistent with our commitment to continuously improve our environmental performance.

Targets are outlined below:

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Alignment with UN 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 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 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 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"
Protecting nature and biodiversity	By 2024, assess and disclose nature-related risks and opportunities including TransAlta’s dependencies and impacts on ecosystems, land, water and air	UN SDG Target 15.5: "Take urgent and significant action to reduce the degradation of natural habitats, halt the loss of biodiversity and, by 2020, protect and prevent the extinction of threatened species”
	Achieve zero biodiversity-related incidents	

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from 2015 base year	UN SDG Target 13.2: "Integrate climate change measures into national policies, strategies and planning"
	By 2045, achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions	
	By 2024, verify and disclose 80 per cent of TransAlta's scope 3 emissions	

ESG Alignment: Social

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.32	UN SDG Target 8.8: "Protect labour rights and promote safe and secure working environments for all workers, including migrant workers, in particular women migrants, and those in precarious employment"
Integrate sustainability into supply chain	By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment	UN SDG Target 12.7: "Promote public procurement practices that are sustainable, in accordance with national policies and priorities"
Support prosperous Indigenous communities	Support equal access to all levels of education for youth and Indigenous peoples through financial support and employment opportunities	UN SDG Target 4.5: "By 2030, eliminate gender disparities in education and ensure equal access to all levels of education and vocational training for the vulnerable, including persons with disabilities, Indigenous peoples and children in vulnerable situations"
	Provide Indigenous cultural awareness training to all TransAlta employees by the end of 2023	UN 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

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	UN SDG Target 5.5: "Ensure women's full and effective participation and equal opportunities for leadership at all levels of decision making in political, economic and public life"
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	
	Maintain equal pay for women in equivalent roles as men	
Demonstrate leadership on ESG reporting within financial disclosures	Maintain our position as a leader on integrated ESG disclosure through increased annual alignment with leading sustainability disclosure frameworks	UN SDG Target 12.6: "Encourage companies, especially large and transnational companies, to adopt sustainable practices and to integrate sustainability information into their reporting cycle"

ESG Alignment: Environmental and Social

Sustainability goal	Sustainability target	Alignment with UN SDG Target or Future-Fit Business Benchmark
Coal transition	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from renewables and gas	UN 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 SDG Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix"

Our 2022 Sustainability Performance

In 2022, we achieved our target to reduce TransAlta's total waste generation by 80 per cent over a 2019 baseline. We also achieved our 2026 targets to reduce air emissions and water consumption. In 2022, TransAlta's strong safety performance was a key accomplishment amongst our social performance metrics. Our TRIF exceeded our exceptional performance target and was our best on record.

Performance against our 2022 sustainability targets is outlined below:

ESG Alignment: Environmental

Sustainability goal	Sustainability target	Results	Comments
Reclaim land utilized for mining	By 2040, complete full reclamation of our Centralia coal mine in Washington State	On track	Reclamation work at Centralia is underway
	By 2046, complete full reclamation of our Highvale coal mine in Alberta	On track	Our Highvale coal mine in Alberta closed on Dec. 31, 2021, and reclamation is underway
Responsible water management	By 2026, reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent over a 2015 baseline	Achieved	Since 2015, we have reduced our fleet-wide water consumption by 20 million m^3 or 43 per cent
Reduce operational waste	By 2022, reduce total waste generation by 80 per cent over a 2019 baseline	Achieved	In 2022, we reduced total waste generation by 1,325,000 tonnes equivalent or 86 per cent over 2019 levels
Reduce air emissions	By 2026, achieve a 95 per cent reduction of SO_2 emissions and an 80 per cent reduction of NOx emissions below 2005 levels	Achieved	Since 2005, we have reduced SO_2 emissions by 98 per cent and NO_x emissions by 83 per cent
Reduce GHG emissions	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year	On track	Since 2015, we have reduced GHG emissions by 68 per cent. In 2022, we reduced approximately 2.3 million tonnes of CO_2e or 18 per cent over 2021 levels
	By 2050, achieve carbon neutrality	On track	

ESG Alignment: Social

Sustainability goal	Sustainability target	Results	Comments
Reduce safety incidents	Achieve a Total Recordable Injury Frequency rate below 0.61	Achieved	In 2022, we achieved a TRIF of 0.39 compared to 0.82 in 2021. Our strong safety performance can be attributed to our focus on maturing our safety culture, reducing hazards, assessing and addressing risk tolerance and standardizing safety information and data collection technology
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 2022 represented a total value of $457,000. For the 2021/2022 year, this included funding for 20 students through our partnership with Indspire and support for the Southern Alberta Institute of Technology academic upgrading program for Indigenous students
	Provide Indigenous cultural awareness training to all TransAlta employees by the end of 2023	On track	In 2022, we provided Indigenous awareness training to all Canadian employees. Australian and US employees will receive the training by the end of 2023

ESG Alignment: Governance

Sustainability goal	Sustainability target	Results	Comments
Strengthen gender equality	Achieve 50 per cent female representation on the Board by 2030	On track	As of Dec. 31, 2022, women made up 36 per cent of our total Board composition compared to 42 per cent in 2021, due to the retirement of one female Board member
	Achieve at least 40 per cent female employment among all employees of the Company by 2030	On track	As of Dec. 31, 2022, women made up 26 per cent of all employees, an increase over 2021 levels (24 per cent)
	Maintain equal pay for women in equivalent roles as men	Achieved	In 2022, we achieved a 99 per cent female/ male pay equity ratio. We reviewed base compensation levels for non-executive, non-union employees, comparing female pay to male pay for employees in comparable positions
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 2022, we received an 'A-' score with CDP (the global disclosure system for environmental impacts known formerly as the Carbon Disclosure Project). This is higher than the North America regional average of C and the thermal power generation sector average of B. In 2022, TransAlta's MSCI ESG Rating was upgraded to 'A' from 'BBB'. The upgrade reflects the Company's strong renewable energy growth compared to peers

ESG Alignment: Environmental and Social

Sustainability goal	Sustainability target	Results	Comments
Leading clean power company by 2025	No further coal generation by the end of 2025 with 100 per cent of our owned net generation capacity to be from clean electricity (renewables and gas)	On track	In 2021, we retired or converted all coal plants in Canada and closed the Highvale coal mine, thus ceasing all coal generation in Canada. Our Centralia plant in the US is set to retire on Dec. 31, 2025
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	On track	In 2022, we have successfully delivered 800 MW of new growth or 40 per cent of incremental renewable capacity. We are on track to meet the target of 2 GW by 2025, as part of our Clean Electricity Growth Plan

Decarbonizing Our Energy Mix

ESG is more than a business strategy at TransAlta; it is a competitive advantage. Sustainability is one of our core values; therefore, we strive to integrate climate change into governance, decision-making, risk management and our day-to-day business operations. The outcome of our climate change focus is continuous improvement on key climate-related issues and ensuring our economic value creation is balanced with a value proposition for the environment and people.

We recognize the impact of climate change on society and our business both today and into the future. Our renewable energy commitment began 111 years ago when we built the first hydro assets in Alberta, which still operate today. In 1997, we began operating our first wind facility, in 2014, our first solar facility and, in 2020, our first battery storage facility. Today, we operate over 50 renewable facilities across Canada, the US and Australia.

Our reporting on climate change management has been guided by the TCFD recommendations since 2018. This framework helps inform discussion and provide context on how climate change affects our business.

Strategy and Risk Management

Climate Change Strategy

As described in the following sections, our risks and opportunities assessment and climate scenarios analysis support the development and continuous improvement of our climate change strategy. We actively monitor and manage climate-related risks and opportunities as part of our overall business strategy to ensure we remain resilient across all scenarios.

TransAlta remains committed to creating a path to resiliency in a decarbonizing world in support of the goals adopted under the Paris Agreement, and the goals adopted during subsequent international climate meetings. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, natural gas, battery storage and coal), the phase-out of coal-fired electricity generation, and the development of renewable energy and storage projects. Our customers are increasingly integrating ESG risk into their business decisions; therefore, we see an advantage in growing our clean power business to support our customers' sustainability goals. Our investments and growth in renewable energy are highlighted by our portfolio of renewable energy-generating assets. From 2000 to 2022, we grew our nameplate renewables capacity from approximately 900 MW to over 2,900 MW. Today, our diversified renewable fleet makes us one of the largest renewable power producers in North America, one of the largest producers of wind power in Canada and the largest producer of hydro power in Alberta.

Another way we contribute to our customers’ sustainability goals is through environmental attributes. The environmental attributes that we generate include carbon offsets, renewable energy credits and emission offsets. Our customers can use environmental attributes to lower compliance costs attributed to carbon policies or renewable portfolio standards. Further, environmental attributes can help achieve voluntary corporate sustainability or carbon reduction goals.

To combat the challenges of renewable energy intermittency, we continue to invest in battery storage. In 2020, we launched WindCharger, a "first of its kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity onto the Alberta grid during system supply shortages, as well as providing critical system support services to the system operator. Further, in 2021, we agreed to provide solar electricity supported with a battery energy storage system to BHP Nickel West through the construction of the Northern Goldfields solar project in Western Australia. This project will support BHP in meeting its emissions reduction targets and delivering lower-carbon, sustainable nickel to its customers. The Northern Goldfields solar project is on track to be completed in early 2023 and is expected to reduce BHP's scope 2 electricity GHG emissions by 540,000 tonnes of CO_2e over the first 10 years of operation. In 2022, TransAlta entered into an engineering, procurement and construction agreement for the expansion of the Mount Keith 132kV transmission system to support the Northern Goldfields solar project. The expansion will facilitate the connection of additional generating capacity to our network to support BHP's operations and increase its competitiveness as a supplier of low-carbon nickel.

In support of our own path to climate resiliency, we have taken significant steps to reduce our carbon footprint over the last several years. In 2021, we adopted a more stringent climate-related target to reduce 75 per cent of our scope 1 and 2 GHG emissions by 2026 from a 2015 base year. We estimate that this target is in line with the latest climate science and the electricity sector decarbonization pathway to limit global warming to 1.5°C and meet the Paris Agreement goals. Furthermore, we adopted an accelerated long-term climate-related target to achieve net-zero for 100 per cent of TransAlta's scope 1 and 2 GHG emissions by 2045. This ambitious target aligns us with the Canadian Net-Zero Emissions Accountability Act to achieve net-zero emissions by 2050.

We are also taking strategic steps to decarbonize the power sector and support the energy transition. In 2022, we achieved a cumulative progress of 800 MW toward our Clean Electricity Growth Plan announced in 2021. The plan will see the Company execute on 2 GW of renewables growth by 2025 and a 5 GW growth pipeline by 2025. In 2023, we are targeting final investment decisions on 500 MW of additional clean energy projects across Canada, the US and Australia. In 2025, we will retire our single remaining coal unit, located in the US, to complete TransAlta's transition away from coal generation.

To date, we have retired 4,664 MW of coal-fired generation capacity since 2018 while converting 1,659 MW to natural gas. Comparatively, our converted natural gas units' CO_2 intensity is approximately 57 per cent less than coal generation. Repurposing the facilities rather than decommissioning them reduces the cost and emissions associated with new construction and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." The completed conversions and the closure of the Highvale coal mine also contribute to the goals of the Powering Past Coal Alliance, which TransAlta joined in 2021 at COP26.

We actively engage policymakers and stakeholders on how to facilitate a transition where the electricity systems we serve can reach net-zero emissions while maintaining reliability. We will continue investing in renewables and assessing the best options to deliver energy storage, including incorporating learnings from our industrial-scale battery into our Company strategy and sharing those learnings with government. At the same time, natural gas will play an essential role in the electricity sector, providing dispatchable generation to support current system demands and a smooth energy transition. We always seek energy-efficiency improvements and opportunities to achieve emissions reductions at competitive costs. Further, we are committed to investing in climate change mitigation solutions to maximize value for our shareholders, customers, local communities and the environment.

Climate Transition Plan

A climate-related transition plan describes how a company aims to minimize climate-related risks and increase opportunities, in alignment with the TCFD recommendations. In 2022, TransAlta developed its first consolidated Climate Transition Plan, which lays out our approach to reducing operational and value chain emissions to deliver net-zero operations by 2045. In addition, our Climate Transition Plan includes sustainable finance and inclusive transition actions reflecting TransAlta's commitment to a successful transition toward a low-carbon economy. For further information, refer to Sustainable Finance in the Decarbonizing Our Energy Mix section of this MD&A and Inclusive Transition in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Our Climate Transition Plan defines TransAlta's past, short-term (2023-2025) and medium- to long-term actions (beyond 2026). For each of these actions, we assessed our ability to control ("C") intended outcomes, partner ("P") with stakeholders to drive outcomes or influence ("I") outcomes that will help us achieve our decarbonization targets.

The highest level of climate change oversight, including the actions of our Climate Transition Plan, is at the Board level. For further information, refer to Oversight by the Board of Directors in the Climate Change Governance section of this MD&A. Information on executive compensation linked to climate-related targets is described in ESG-Linked Compensation in the Building a Diverse and Inclusive Workforce section of this MD&A. Metrics and targets supporting our Climate Transition Plan, including climate-related financial metrics, are described in Climate Change Metrics and Targets in the Decarbonizing Our Energy Mix section of this MD&A.

Delivering Net-Zero Operations by 2045

	Past actions	Short-term actions (2023-2025)	Medium to long-term actions (2026 +)
Hydro	Became the largest producer of hydro power in Alberta (C)	Deliver 2 GW of incremental renewable capacity with a targeted capital investment of $3.6 billion by the end of 2025 (C) Achieve 70 per cent of EBITDA from renewables and storage by the end of 2025 (C) Accelerate growth in customer-centred renewable energy solutions through the deployment of our 5 GW development pipeline by the end of 2025 (C)	Enable a two-fold increase in renewables by 2030 (C) Develop new opportunities for growth in renewables and storage by 2030 (C)
Wind and Solar	From 2000 to 2022, we grew our nameplate renewables capacity by approximately 2,000 MW (C) In 2022, announced 200 MW of new build projects and 100 MW of advanced-stage wind development projects (C)		
Battery Storage	First battery storage facility delivered in 2020 (C) In 2022, started the construction of a 48 MW solar and battery storage system in Australia (C)	Develop up to 180 MW battery storage in Canada (C) Evaluate and deploy battery storage alongside renewable facilities where appropriate (C)	
Natural Gas	Completed our coal-to-gas conversions in Canada in 2021 (C) Converted 1,659 MW from coal to natural gas since 2018 (C)	Operate simple-cycle, combined-cycle and cogeneration facilities in Canada, the United States and Australia (C) Assess deployment of nature-based or engineered solutions to neutralize unabated gas-fired generation where appropriate (C) Evaluate use of renewable and low-carbon natural gas (C)	Neutralize residual emissions from gas-fired generation through fuel switching, new technologies or nature-based solutions (C)
Emerging Abatement Technologies and Solutions	Started exploring new technologies such as storage, hydrogen and carbon capture (P) In 2022, supported the development of low-cost, low-emissions hydrogen production through $2 million investment in a Canadian-based venture (P)	Identify the next generation of power solutions and technologies and potential for parallel investments in new complementary sectors by the end of 2025 (P) Assess ways to support customers with broader decarbonization technologies beyond electrification (P) Partner with leading global companies to target early-stage revolutionary technologies through a US$25 million investment in a deep decarbonization fund (P) Identify opportunities to partner, pilot and deploy novel, net-zero generation technologies (P) Assess and deploy GHG removal technologies where appropriate (C)	Deploy new net-zero generation technologies and solutions where appropriate (C) Choose materials, products and processes that generate fewer GHG emissions, mainly through energy savings (C)
Energy Transition (Coal)	Retired 4,664 MW of coal-fired generation capacity since 2018 including ending coal generation in Canada in 2021 (C) Closed last coal mine in 2021 (C)	Continue to execute reclamation work at our coal mines (C) Contribute to a circular economy through mining waste reuse or by-product sales (C)	Cease coal generation by 2026 (C) Complete full reclamation in Washington State by 2040 and in Alberta by 2046 (C)

Legend: (C) Control intended outcomes, (P) partner with stakeholders to drive outcomes, and (I) influence outcomes that will help us achieve our decarbonization targets.

Delivering Net-Zero Operations by 2045 (Continued)

	Past actions	Short-term actions (2023-2025)	Medium to long-term actions (2026 +)
Supply Chain	Enhanced supplier management functionality within the corporate procurement system (C)	Develop ESG criteria for supply chain engagement (C) Understand direct suppliers, GHG emissions profile and targets (C) Incorporate ESG data reporting capability in corporate procurement system (C)	Engage with suppliers to explore enhancement of their GHG emissions reduction targets (I) Set direction for engaging suppliers with GHG emissions reduction targets (C)
Value Chain	Disclosed range of scope 3 GHG emissions at company level (C)	Update scope 3 GHG emissions reporting methodology (C) Verify and disclose 80 per cent of our total scope 3 emissions (C)	Consider scope 3 GHG emissions targets (C)
Sustainable Finance	In 2021, converted existing $1.3 billion loan into a Sustainability-Linked Loan aligned with GHG emissions reduction and female employment targets at the company level (C) In 2021, secured $173 million green bond financing for eligible wind project in Alberta (C) In 2022, issued US$400 million Senior Green Bonds for eligible renewable energy and energy-efficiency projects (C) Linked ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to fund renewable energy and battery storage projects (C) Link ESG performance to employees' and executive remuneration (C)	Continue to evaluate the use of sustainable or green financing instruments to grow our renewables and storage capacity (C)
Inclusive Transition	Developed a five-year Equity, Diversity and Inclusion (ED&I) strategy (C) Conducted ED&I census to help drive a greater sense of belonging for all employees across our company (C) Set organizational health and ED&I targets as part of ESG-linked compensation (C) In 2015, announced community investment of US$55 million over 10 years to support energy efficiency, economic and community development and education and retraining initiatives in Washington State (P) In 2016, agreed to invest in the communities impacted by the phase-out of coal generation in Alberta (P)	Expand number of employee resource groups available (C) Adapt workplaces to incorporate structural changes for inclusive work environments (C) Deliver year-round ED&I learning and awareness, and celebration campaigns (C) Continue energy transition investment in Washington State communities of up to US$55 million by 2025 (P) Continue to invest in the communities impacted by the phase-out of coal generation in Alberta (P) Strengthen Indigenous relations focused on community engagement and consultation, community investment and partnership opportunities (P) Provide Indigenous cultural awareness training to all employees by the end of 2023 (C) Promote supplier diversity in our operations (C)	Implement employee resource groups with the support of ED&I partners (P) Enhance recruitment and retention of female employees to achieve gender-based targets (C) Maintain succession practices to increase female representation at senior management level (C) Increase female representation in Generation by encouraging women to pursue a career in electricity (C) Enhance opportunities for diverse suppliers in our procurement processes (C) Continue to enhance our Indigenous relations focused on partnership opportunities with local communities (P) Ongoing support to local community organizations aligned with our community investment pillars where we operate and grow communities (P)

Climate Change Governance

Climate-related risks and opportunities can significantly impact our business, especially regulatory changes and shifting customer preferences toward lower-carbon energy. Therefore, we actively manage risks and opportunities so that we can continue to grow and achieve our goals. Climate-related issues are identified at every level of management, including the Board, executive team, business units and corporate functions (for example, government relations, regulatory, emissions trading, sustainability, commercial, customer relations, investor relations). Ensuring climate-related issues are acknowledged and addressed at the most senior levels of the Company (including at the Board and executive level) has allowed us to establish actionable emissions reduction targets and grow our generation capacity through renewable energy and storage.

Oversight by the Board of Directors

The highest level of climate change oversight is at the Board level, with specific oversight of certain aspects of the Company's response to climate change being delegated to our Governance, Safety and Sustainability Committee (“GSSC”), our Audit, Finance and Risk Committee ("AFRC") and our Investment Performance Committee (“IPC”) of the Board.

Meeting quarterly, the GSSC assists the Board in monitoring and assessing compliance with climate change regulation and reporting. The GSSC receives management reports from the Executive Vice President ("EVP"), Legal, Commercial and External Affairs on changes in climate-related legislation and the potential impact of policy developments on TransAlta's business. The GSSC then supports the Board in developing Company-wide climate change strategies, policies and practices. The GSSC also reviews environmental protection guidelines, including with respect to GHG mitigation, and considers whether our environmental procedures are being effectively implemented.

The AFRC and IPC also play a role in managing TransAlta's climate-related risks and opportunities. The AFRC assists the Board in overseeing the integrity of our consolidated financial statements and ensures climate risks and opportunities are factored into financial decision-making. Further, the AFRC is responsible for approving our Commodity and Financial Exposure Management policies and reviewing quarterly ERM reporting. The IPC considers and assesses risks related to capital investment projects, including overseeing climate risk assessments and mitigation plans. As a result, climate-related capital expenditures, acquisitions and budgets are reviewed by the AFRC and IPC on a case-by-case basis.

The Board reviews and updates the Company's strategy annually. In 2022, the Board's strategic planning sessions included climate-related issues considering growth initiatives and strategies, capital allocation and other matters. Our Board is composed of individuals with a mix of skills, knowledge and experience critical to our strategy success and business growth. In 2022, four of our 11 Board members identified environment/ climate change among their top four relevant competencies.

Role of Senior Management

TransAlta’s President and CEO maintains the highest level of oversight on climate-related issues at the executive level. Our EVP, Legal, Commercial and External Affairs provides the Board, as well as the President and CEO, with updates on climate-related risks and opportunities to inform business strategy and to ensure alignment with TransAlta’s GHG emissions reduction goals. Our business units and corporate functions work closely together to support the executive team in understanding climate-related risks and opportunities. Our executive team reviews risks and opportunities quarterly and reports to the GSSC and AFRC.

At the business unit level, climate change risks are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups.

Notably, we tie a component of executive compensation to reducing GHG emissions and climate change management. We link our annual incentive plans (short-term incentive and long-term incentives) to our strategic goals. Our strategic goals include growing renewable energy, reducing GHG emissions and supporting our customers' sustainability goals to decarbonize through on-site low carbon energy generation.

For further information on incentives for ESG performance, refer to the discussion on ESG-Linked Compensation in Building a Diverse and Inclusive Workforce section of this MD&A.

Climate Scenarios

In 2021, we conducted climate scenario analysis to understand risks and opportunities and assess our strategy's resiliency under several potential future climate scenarios. The analysis utilized scenarios from the International Energy Agency's ("IEA") 2020 World Energy Outlook, a large-scale simulation model designed to replicate how energy markets function. We used three scenarios: Stated Policies ("STEPS"); Sustainable Development ("SDS"); and Net-Zero Emissions by 2050 ("NZE").

In STEPS, the energy system has no major additional climate and environmental policies enacted by government(s). STEPS assumes that carbon pricing continues in Canada while no carbon price is set in the US or Australia. STEPS also assumes that the power sector reduces emissions by 45 per cent by 2040 while natural gas generation capacity increases. Finally, STEPS is limited to the deployment of commercial-ready technologies, including wind and solar.

In SDS, the goals of the Paris Agreement (2015) are achieved, resulting in net-zero emissions by 2070. The SDS assumes a rapid increase in clean energy policies and investments that position the energy system to also achieve key UN SDGs. In SDS, all current net-zero pledges are achieved and there are extensive efforts to reduce emissions. SDS assumes that carbon pricing continues in Canada and is set in the US and Australia. It also assumes that the power sector reduces emissions by 90 per cent by 2040 while natural gas capacity remains stable into 2030 and declines toward 2040. Finally, SDS assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of carbon capture, utilization and storage ("CCUS") and hydrogen.

NZE represents a pathway for the global energy sector to achieve net-zero emissions by 2050. This scenario also assumes key energy-related SDGs are achieved through universal energy access by 2030 and major improvements in air quality. NZE is built upon the idea that a global increase in electrification supports the journey to net-zero. It assumes that an aggressive carbon price is set in Canada, the US and Australia. It also assumes the power sector reaches net-zero emissions by 2035 in advanced economies while natural gas capacity is stable to 2030 and declines significantly into 2040. Like the SDS, NZE assumes that beyond wind and solar, the energy system relies on batteries, storage and some level of CCUS and hydrogen.

In 2022, we reviewed the findings from the climate scenario analysis and updated the management response accordingly.

Key Climate Scenario Findings

Using climate scenarios, we analyzed the resiliency of our business and determined specific risks and opportunities for our individual assets. All three scenarios present opportunities for TransAlta's growth related to renewables, storage solutions and ancillary services. The scenario analysis found that our wind and solar assets have the highest prospects for growth, which aligns with our growth strategy. Under all scenarios, hydro remains a valuable asset as it allows for expansion to include storage.

The following sections highlight TransAlta's top risks, opportunities and management response across all scenarios.

Top Identified Climate-Related Risks by Scenario

	Increased competition	Decreased demand of natural gas electricity	Increased operational costs
Description	Subsidies/funds available for clean energy transition increase as governments aim to grow installed capacity of renewables to meet rising electricity demand and compensate for the closure of carbon-intensive power plants. In Canada, it is expected that major grid decarbonization investments will flow into Alberta as most other provincial markets are heavily regulated and/or are already low carbon. This will increase competition in the merchant market, making a large part of the generating fleet frequently bid at zero, driving down the average price of dispatched electricity. Simultaneously the cost of renewables, expected to decline across all scenarios, decreases the capital barrier to entry. These combined factors will increase competition for TransAlta. The IEA scenarios do not provide clear indication of electricity pricing and how it can be affected by increased competition. As such, this remains a point of uncertainty. Some structural market changes may be required to guarantee returns for power generators and successfully decarbonize the grid.	Demand for power from natural gas declines as the market shifts towards cleaner power with gas shifting to a reliability backstop role. An additional decline from Canadian oil and gas customers can occur as oil production levels drop under NZE and SDS. The transition to a lower-carbon world will likely result in volatility and market uncertainty. Counterintuitively, natural gas power may be necessary to provide power in the transition if the pace of decarbonization is slower than expected in the scenarios or if grid-scale storage solutions do not develop/ commercialize as modelled. In these cases, with coal phased out, natural gas assets will be relied on for baseload generation. This means that natural gas assets may still play a role for a smooth and efficient energy transition. Optimization of natural gas assets is required, and additional investments need to be assessed with caution to consider the pace of decarbonization and consequent risk of decreased demand for natural gas power.	Carbon price increases the cost of natural gas operations. Additional mandated emissions reductions could force remaining plants to invest in technologies like CCUS, increasing the operating costs for natural gas plants further. Natural gas assets in the US and Australia face less risk compared to assets in Alberta as they are contracted and can pass down carbon costs to their clients. Current and anticipated regional carbon pricing monitoring is required to plan and assess increases in operational costs and impacts on new projects and investments.
NZE	By 2040, renewables are expected to comprise over 85 per cent of the total electricity generation in the regions we operate. This surge in renewables will increase competition and drive electricity pricing down depending on availability and the cost of energy storage. The change in electricity prices and increased market uncertainty are expected to impact our profits.	The share of natural gas electricity generation is expected to decline over 50 per cent in the regions in which we operate by 2040 compared to 2019 levels. This lower demand for natural gas power is expected to impact our natural gas assets if no management responses are implemented.	Higher operational costs driven by an increase in carbon price to US$205/ tonne CO_2e by 2040 in all our operating regions (advanced economies under IEA scenarios) and lower operational capacity is expected to impact the profits from our natural gas assets.

Top Identified Climate-Related Risks by Scenario

	Increased competition	Decreased demand of natural gas electricity	Increased operational costs
SDS	Fewer subsidies/funds are expected under this scenario compared to NZE. However, renewable costs will still decline approximately 10 per cent in wind and 55 per cent in solar by 2040 compared to 2019 levels. This decline with some level of subsidy will increase competition and potentially decrease electricity prices, which is expected to impact our profits.	Natural gas electricity generation still falls over 50 per cent in North America while remaining flat in Australia by 2040 when compared to 2019 levels. Demand for natural gas power is expected to decrease at a slower pace than under NZE. This could potentially impact our natural gas assets if no management responses are implemented.	Increase in operational costs would happen at a slower rate compared to NZE but carbon costs are still expected to reach US$140/tonne CO_2e by 2040 in all of our operating regions. This could potentially impact the operational capacity and profits from our natural gas assets, depending on the ability to pass carbon prices on through our contracts.
STEPS	While minimal subsidies are expected and the cost of entry will not decline at the same rate as SDS or NZE, renewable costs are still expected to decline approximately 8 per cent in wind and 45 per cent in solar by 2040 compared to 2019 levels. This will still cause an increase in competition that is expected to be offset by additional electricity demand and therefore it is not expected to impact our profits.	Natural gas electricity generation is expected to increase over 15 per cent in the regions in which we operate by 2040 compared to 2019 levels. These changes are not expected to affect our natural gas assets.	Operational costs are not expected to significantly increase under this scenario as only Canada sees a carbon price in 2040. Therefore, profits from our natural gas assets are not expected to be affected.
Management Response	Navigating the uncertainty around market dynamics (structure, pricing and competition), government policies and planning is critical for TransAlta. We use hedging and PPAs to stabilize pricing and are planning on leading clean energy growth in the regions in which we operate. See more details of our strategy and risk management under the Climate Strategy section and the Managing Climate Change Risks and Opportunities section of this MD&A.	Optimize gas assets to maximize value and cash flows to support renewables and storage growth. Our converted natural gas units' CO_2 intensity is approximately 57 per cent less than coal generation. Repurposing the coal facilities rather than decommissioning them reduces the cost and emissions associated with new construction and aligns with the UN SDGs, specifically "Goal 9: Industry, Innovation and Infrastructure." In parallel, we continue growing our renewable fleet; by the end of 2025 we will have achieved a 100 per cent portfolio mix of renewables and natural gas with 70 per cent of EBITDA attributable to renewables.	We have taken significant steps to reduce our carbon footprint. Since 2015, we have reduced GHG emissions by 68 per cent. By 2026, we have a commitment to reduce scope 1 and 2 GHG emissions by 75 per cent from 2015 base year and plan to achieve net-zero emissions by 2045. Further, our corporate functions apply regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks of uncertainty in the carbon market.

Top Identified Climate-Related Opportunities by Scenario

	Renewables become major energy source	New technology development
Description	Opportunities to grow the renewable fleet exist across all scenarios. Renewable assets (hydro, wind, solar) are expected to become the default form of generation with demand for power from these types of assets increasing. Hydro is likely to grow in value given increased renewables penetration and the need for reliable zero-emitting generation. This can make hydroelectric power a stronger source of baseload electricity in many regions. The decreasing cost of renewables also facilitates the growth of a renewable fleet, especially under NZE and SDS.	Opportunities for development of battery or hydroelectric storage systems and ancillary services exist across all scenarios as renewable energy continues to penetrate the grid. Developments in these areas are required to keep electricity flowing when the renewables in a region are not producing. Storage is especially anticipated to play an important role in the energy transition. Cost-competitive battery storage enables greater adoption of renewables.
NZE	A growth of renewable electricity generation of approximately 950 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 85 per cent of the electricity generation in the regions in which we operate. The transition of hydro to baseload capacity is expected to create upside for TransAlta. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under NZE. With more than 85 per cent of electricity in areas in which we operate made up of renewables, there will be big steps forward in storage and ancillary services technologies. Storage capacity is expected to grow to approximately 250 GW in the US by 2040.
SDS	A growth of renewable electricity generation of approximately 550 per cent is expected by 2040 compared to 2019 levels. This results in renewables comprising more than 75 per cent of the electricity generation in the regions in which we operate. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Increased revenues through access to new and emerging markets are expected to enable growth and higher revenues under SDS. A lower share of renewables than in NZE will allow swing production to remain present; however, growth in ancillary and storage capacity will still be needed to support the market. Storage capacity is expected to grow to approximately 110 GW in the US by 2040.
STEPS	STEPS growth is muted relative to the other scenarios but still sees a growth of renewables of 280 per cent by 2040 compared to 2019 levels. This growth will allow approximately 50 per cent of electricity generation to come from renewables in areas in which we operate by 2040. An increase in TransAlta's renewable capacity and demand are expected to enable growth and higher revenues.	Access to new and emerging markets would be limited under this scenario compared to NZE and SDS. While growth in renewables is expected, the need for new technologies is not a necessity in this market and may not be profitable. Therefore, our revenues are not expected to be affected.
Management Response	Our renewable energy commitment began more than 100 years ago when we built the first hydro assets in Alberta, which still operate today. We now operate over 50 renewable facilities across Canada, the US and Australia. By the end of 2025, we expect 70 per cent of our EBITDA to be derived from renewables. Our strategy is focused on the operation of our existing assets (wind, hydro, solar, gas, storage and coal) and the development of renewable energy, storage and low-carbon natural gas generation. Our investments and growth in renewable energy are highlighted by our portfolio of renewable energy-generating assets. From 2000 to 2022, we grew our nameplate renewables capacity from approximately 900 MW to over 2,900 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.	To leverage this opportunity and combat the challenges of renewable energy intermittency, we continue to invest in battery storage. In 2020, we launched WindCharger, a "first of its kind in Alberta" battery storage project that stores energy produced by our Summerview II wind facility and discharges electricity onto the Alberta grid during system supply shortages. Further, in 2021, we agreed to provide renewable solar electricity supported with a battery energy storage system to BHP Nickel West through the construction of the Northern Goldfields solar project in Western Australia. This project will support BHP in meeting its emissions reduction targets and delivering lower-carbon, sustainable nickel to its customers. Construction began in 2022 and is on track to be completed in early 2023.

NZE: The most significant risks include increased competition, decreased demand for natural gas and increased operational costs due to increased carbon pricing and emissions reduction mandates. The most significant opportunities include a shift toward renewables as the default energy source and new technology developments, including battery storage systems and ancillary services. It is worth noting that there are additional risks and opportunities for TransAlta under NZE. For example, changes in how energy market services are offered could positively or negatively impact our business. Further, as carbon credit policies evolve, so will our ability to use credits. Lastly, as renewables become the primary energy source, a rethinking of ancillary services will be necessary but could create significant opportunities for TransAlta.

SDS: The risks and opportunities remain the same under SDS as NZE; however, the impacts are reduced as market changes are slower and less extreme. Renewables still become the primary electricity source and there are new technology opportunities, particularly in batteries. Natural gas electricity demand still declines by 2040. Carbon pricing exists in the US and Australia, but the price is reduced compared to NZE. Lastly, a reevaluation of ancillary services still presents an opportunity for TransAlta.

STEPS: Under STEPS, renewable generation sees significant growth but does not become the predominant energy source. Implementing new technologies is much slower and the demand for batteries is reduced. The demand for natural gas electricity does not decline and there are no large-scale market changes making services, pricing and ancillary services more stable. This removes the risk associated with natural gas electricity demand but eliminates the opportunity for growth in ancillary services. Physical risks become more relevant under this scenario than transitional risks.

To mitigate risks and capitalize on opportunities, we have developed climate signposts to monitor the evolution of future climate scenarios. Signposts are indicators that suggest the likelihood of a particular climate scenario. Examples of signposts include directional change in carbon and oil prices. The findings from the climate scenarios and these signposts work alongside our sustainability metrics and targets to inform the evolution and resiliency of our Company's strategy and financial planning, risk management, opportunity assessment and planning for uncertainty.

Managing Climate Change Risks and Opportunities

We actively monitor and manage climate-related risks through our company-wide enterprise risk management processes. In 2021, we established a formal process to review specific risks using climate scenario analysis. As previously mentioned, climate change risks and opportunities are addressed at each of the Board level, executive and management level, business unit level and through our corporate functions. The business units and corporate functions work closely together and provide information on risks and opportunities to management, the executive team and the Board.

Climate change risks at the asset or business unit level are identified through our Total Safety Management System, asset management function and systems, energy and trading business, communication with stakeholders, active monitoring and participation in working groups. All identified material risks are added to our ERM register and scored based on likelihood and impact. We do not consider risks in isolation and major risks are the focus of management response and mitigation plans. Further discussion can be found in the Governance and Risk Management section of this MD&A.

We divide our climate change risks into two major categories as per guidance from the TCFD: (i) risks related to the transition to a lower-carbon economy; and (ii) risks related to the physical impacts of climate change.

Transition Risks to a Lower-Carbon Economy

We actively aim to understand and manage the impact of climate change on our business as the world shifts to a lower-carbon society.

Policy and Legal Risks

Changes in current environmental legislation do have, and will continue to have, an impact upon our operations and our business in Canada, the US and Australia.

For a more detailed assessment of policy and regulatory risks, refer to the Governance and Risk Management section of this MD&A.

Canada

The Government of Canada has set out ambitious objectives for carbon emissions reduction, including achieving a 40 to 45 per cent national emissions reduction over 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The Government plans to rely on several policy tools to achieve its emissions objectives, including carbon pricing, emissions performance regulations, funding for industrial energy transition, a Clean Fuel Regulation and incentives for consumers.

In 2021, a Supreme Court of Canada decision confirmed the federal government has significant authority to set national carbon pricing standards. We anticipate the federal government will use this authority to align provincial carbon pricing systems with national carbon targets. Canada’s provinces have significant jurisdiction over their respective electricity sectors and play an important role in setting carbon pricing policy and emissions performance standards, as well as developing and operating their own funding and incentive programs. Negotiation to align carbon pricing, funding and regulatory standards will likely require significant effort and create the risk of tension and misalignment between federal and provincial governments.

Risks

- Escalation in carbon prices and emissions performance regulation may impact TransAlta’s natural gas generation fleet in Canada as governments escalate policy stringency to meet 2030, 2035 and 2050 targets.
- Increased government funding for industrial energy transition may create out of market incentives for competing generation.
- Regulatory incentives, including emissions reduction crediting, may create out of market incentives for competing generation.
- Lack of federal/provincial coordination with respect to climate policy and regulation may lead to investment uncertainty.

Opportunities

- Independent estimates suggest that achieving Canada’s climate targets will require a minimum of twice Canada’s current non-emitting generation. This presents strong policy alignment with TransAlta’s Clean Electricity Growth Plan. Further, we continue to see strong private sector demand for contracted zero emissions generation to meet corporate sustainability goals.
- Government funding for innovative technology to reduce emissions from the electricity sector offers TransAlta the potential opportunity to gain project support for uneconomic new technologies, which will enable the Company to grow its ESG and policy-aligned generation and energy storage fleet.
- Government support for industrial electrification and consumer incentives mandates for electrification, such as for the purchase of electric vehicles, will grow the electricity load over time and create new opportunities for contracted clean generation.

Management Response

- TransAlta's Clean Electricity Growth Plan positions our company to meet the rapidly growing demand for clean electricity generation driven by customers and government policy.
- We are focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue and eligibility for government incentive programs. TransAlta actively assesses available government renewable tax legislation and programs to maximize, wherever possible, access to project incentives.
- Our clean and contracted growth reduces the proportional Company exposure to potential policy and regulatory decisions that negatively impact natural gas generation.
- Our coal-to-gas facilities fit within government plans to continue providing reliable and competitively priced electricity for consumers and industry.
- Our remaining natural gas facilities operate under contract, reducing TransAlta's exposure to changes in carbon pricing.
- TransAlta actively engages with the federal and provincial governments in Canada to inform and influence policy development to ensure that our generating fleet continues to serve our customers as the country undertakes a broader energy transition.
- We actively work, directly and through industry associations, to encourage governments to adopt a level playing field within funding and crediting programs so that all new projects receive equitable government incentives and funding.
- TransAlta actively engages with all relevant Canadian governments to seek policy alignment across carbon pricing and regulatory and funding programs to create the greatest possible degree of investment certainty.

United States

The US Government has set out ambitious objectives for carbon emissions reduction, including achieving a 50 to 52 per cent national emissions reduction over 2005 levels by 2030, a net-zero electricity grid by 2035 and a net-zero national economy by 2050. The US does not have a national carbon pricing regime but does offer federal incentives for renewable generation and energy storage.

State and regional climate and market policies have a significant impact on the pace of energy transition in the US with many governments operating under renewable portfolio standards and carbon pricing regimes. Similar to Canada, independent estimates suggest that the US will require substantial growth in zero-emissions generation to meet its national climate targets.

Risks

- TransAlta operates two thermal generating facilities in the US that could be subject to short-term climate policy changes, but our exposure to this policy risk is low (refer to Management Response below).
- Significant new federal incentives for clean energy could increase competition in the renewables space.

Opportunities

- Achieving government climate goals and private sector sustainability commitments will require rapid and sustained growth in zero-emissions electricity generation over the coming decades. TransAlta's Clean Electricity Growth Plan is focused on providing renewable electricity to contracted customers in a manner aligned with federal, state and private sector goals.
- US tax incentive programs offer significant support for new renewable projects, making the US an attractive growth market.

Management Response

- TransAlta's single coal unit in Washington State is subject to a retirement agreement with the state government that exempts the facility from carbon pricing prior to its end of life in 2025. TransAlta's cogeneration unit at Ada operates under a contract that reduces the Company's exposure to policy risk.
- Our Clean Electricity Growth Plan is focused on developing and acquiring contracted assets that provide long-term certainty with respect to revenue and eligibility for government incentive programs. TransAlta actively assesses available government renewable tax legislation and programs to maximize, wherever possible, access to project incentives.

Australia

The Government of Australia has a 43 per cent national emissions reduction target over 2005 levels by 2030 and a goal to achieve a net-zero national economy by 2050. The government is currently considering changes to the Safeguard Mechanism but these changes are not expected to have a material impact on TransAlta's assets. Australian state governments have all adopted net-zero goals and a number of states have interim targets for 2030 and 2040. These state policies are driving demand for zero-emissions electricity and energy storage.

Risks

- TransAlta's Australian natural gas assets may face policy risk related to changes in government policies but remain well positioned to mitigate those risks (refer to Management Response below).

Opportunities

- Our Clean Electricity Growth Plan is focused on building new, clean generation in Australia and other markets. Government policies and funding programs are generally supportive of the types of projects contemplated within TransAlta's strategy.
- Strong corporate demand for clean energy solutions in Australia's natural resource sectors present opportunities for TransAlta to leverage its existing expertise to help customers reach their decarbonization objectives.

Management Response

- Through our Clean Electricity Growth Plan, TransAlta continues to deliver clean energy solutions to natural resource customers in Western Australia. Our growing suite of technologies, including renewables and energy storage, positions us to provide contracted solutions to customers focused on the need for reliable and sustainable energy.
- TransAlta also continues to assess opportunities to grow our clean energy generation in alignment with Australia's national and state climate goals.
- TransAlta's assets are predominantly contracted with an ability to pass through carbon compliance costs and serve remote industrial load. As a result, the Company faces reduced policy risk.

Technology Risks

Technological changes to support the low-carbon transition present both risks and opportunities for TransAlta. We evaluate existing and emerging impacts of technology through our Energy Innovation team and our ERM process. Examples of technology risks and opportunities include infrastructure changes (such as the shift to distributed energy and away from large-scale power generation infrastructure assets and projects) and digitization combined with greater adoption of energy efficiency (less use of our end product). Cost-competitive battery storage will enable greater adoption of renewables and 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. In 2020, we completed our first battery storage (10 MW) project at one of our wind facilities in southern Alberta. In 2021, we agreed to deliver a hybrid system of solar with battery storage (48 MW) in Western Australia. We continue to investigate the possibility of battery storage at our other facility locations. Our teams continuously adopt improved technology at each of our new developments, which helps protect our shareholder value and maintain reliable and affordable electricity delivery.

We are well-positioned to take advantage of technological opportunities in storage through hydro and/or battery power. We are also well-positioned to take advantage of advancements in renewable technologies as we build new facilities. We are actively accelerating our renewable growth strategy, with $3.6 billion in investment and 2 GW of growth planned by 2025. We will continue monitoring new technologies such as storage, hydrogen and CCUS for future deployment.

For further information on technology and innovation, refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Market Risks

Our major market risks are associated with our coal and natural gas assets. Increased costs for natural gas supply due, in part, to carbon pricing changes could impact our operating costs. We actively monitor market risks through our energy marketing and asset optimization teams and our ERM process. We manage the market risks to our coal assets by converting them to natural gas and plan to fully transition off coal by 2025. Further, our corporate functions apply regionally specific carbon pricing, both current and anticipated, as a mechanism to manage future risks of uncertainty in the carbon market. To simultaneously manage our risks and leverage market opportunities, we continue operating our hydro, wind and solar facilities and are investing in expanding our renewable energy fleet.

We currently have over 20 renewable projects that are either under construction or in the development stage. We are committed to growing our clean energy fleet and, since 2019, have added over 400 MW of renewables and storage, including utility-scale battery storage. Further, we established organized Canadian, US and Australian clean energy growth teams. In 2022, the Company announced 200 MW of new build projects. TransAlta has established a pipeline of potential growth projects that includes 374 MW of advanced stage development projects along with 3,891 to 4,991 MW of projects in earlier stages of development. Our renewable fleet makes our overall portfolio more resilient to climate risk, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Lastly, we recognize the opportunity to grow our ancillary services, such as systems support, providing flexibility to the decarbonizing grid.

Reputation Risks

Negative reputational impacts, including revenue loss and reduced customer base, are evaluated through our ERM process. In the past, we experienced negative reputational impacts due to our coal operations, including a negative impact on the market price of our common shares. Our clear transition path away from coal mitigates this reputational risk. As consumer trends move in favour of renewable and clean electricity, we are investing in a diversified mix of renewable generation and optimizing our natural gas fleet. We continue to actively monitor and manage reputational risks by delivering renewable power solutions while maintaining competitive costs and reliability.

Physical Risks of Climate Change

As we learn more about the physical risks associated with climate change, we continue to consider acute and chronic risks that could significantly impact our operations. We continue to investigate the physical impacts of climate change on our operating assets.

Acute Physical Risks

We have operating assets in three countries and varied geographic locations, many of which could be impacted by extreme weather events. We continuously evaluate the potential impact of acute climate change on our business. Our facilities, construction projects and operations are exposed to potential interruption or loss from environmental disasters (e.g., floods, strong winds, wildfires, ice storms, earthquakes, tornados, cyclones). A significant climate change event could disrupt our ability to produce or sell power for an extended period. Therefore, we strive to mitigate future impacts with climate adaptation solutions.

For example, our gas facility at South Hedland, Australia, is built with climate adaptation in mind. We designed the facility to withstand a category 5 cyclone (the highest cyclone rating). We have mitigated the risk of floods that can occur in the area by constructing the facility above normal flood levels. In 2019, a category 4 cyclone hit this facility but did not impact operations. We were able to continue generating electricity through the storm despite widespread flooding and the shutdown of the nearby port. In Canada, as we near the 10 year anniversary of the 2013 floods in Southern Alberta, we continue to implement projects that increase the resilience of our hydro facilities to severe climate events. We have also modified operations at several of our facilities as per an agreement with the Government of Alberta. This reduces flood risk in the spring while also recognizing the potential for increased droughts as a result of climate change in the future. TransAlta continues to participate in multi-stakeholder groups developing options for climate resiliency across Southern Alberta.

For further information on weather-related risks, refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

Chronic Physical Risks

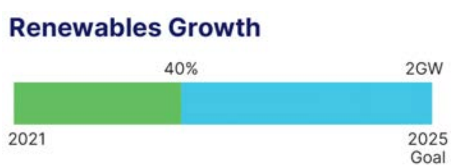
We continuously investigate the physical impacts of longer-term shifts in climate patterns on our operating assets and actively integrate climate modelling into our long-term planning. For example, changes to water flow or wind patterns could impact our hydro and wind businesses and associated revenue generation.

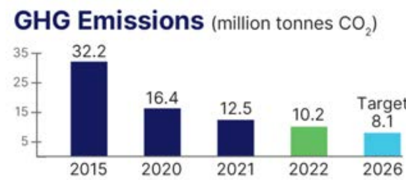
Climate Change Metrics and Targets

Metrics and Targets

At TransAlta, climate change management and performance are a top priority. We established our climate-related goals and targets with reference to the UN SDGs. Over time, we have set ourselves apart with actions that demonstrate climate change leadership.

Progress towards our climate-related targets are presented below:

Clean energy growth		
Sustainability Target	Develop new renewable projects that support our customers' sustainability goals to achieve both long-term power price affordability and carbon reductions.	No further coal generation; 100 per cent of our owned net generation capacity from renewables and gas.
Year	2022	2025
Progress		
Notes	Examples of renewable energy projects in 2022 include the construction of: our Garden Plain wind project in Alberta, which is subject to a PPA with Pembina Pipeline (100 MW) and an investment-grade globally recognized customer (30 MW); our White Rock wind projects in Oklahoma (300 MW), which are subject to two PPAs with Amazon; our Horizon Hill wind project in Oklahoma (200 MW), which is subject to a PPA with a subsidiary of Meta; and our Northern Goldfields solar project with a battery energy storage system in Western Australia (48 MW), which is subject to a PPA with BHP.	In 2022, our owned net generation capacity from renewables and gas represented approximately 89 per cent of our total 6,246 MW owned net generation capacity. In 2021, we achieved full phase-out of coal in Canada. In the US, the remaining unit at Centralia is set to retire on Dec. 31, 2025.
UN SDG Alignment	Target 7.2: "By 2030, increase substantially the share of renewable energy in the global energy mix".	Target 7.1: "By 2030, ensure universal access to affordable, reliable and modern energy services”.

Emissions reduction		
Sustainability Target	By 2026, achieve a 75 per cent reduction of scope 1 and 2 GHG emissions from a 2015 base year.	Achieve carbon neutrality
Year	2026	2050
Progress		
Notes	We are well on track to achieve our target of 75 per cent GHG emissions reductions by 2026. Since 2015, we have reduced GHG emissions by 22 million tonnes of CO_2e or 68 per cent.	In 2022, we reduced approximately 2.3 million tonnes of CO_2e or 18 per cent over 2021 levels. In 2022, we adopted a more ambitious target to be net-zero by 2045. We believe our Clean Electricity Growth Plan supports achieving a more ambitious target.
UN SDG Alignment	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".	Target 13.2: "Integrate climate change measures into national policies, strategies and planning".

GHG Disclosures

Our GHG emissions are calculated using a number of different methodologies depending on the technologies available at our facilities. Emissions data has been aligned with the “Setting Organizational Boundaries: Operational Control” methodology set out in the GHG Protocol: A Corporate Accounting and Reporting Standard developed by the World Resources Institute and the World Business Council for Sustainable Development. We report emissions on an operation control basis, which means we report 100 per cent of emissions at the facilities that we operate.

The GHG Protocol 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 1 or 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.

We compile our corporate GHG inventory using our business segment GHG calculations. As a result, emission factors and global warming potentials used in our GHG calculations can vary due to difference in regional compliance guidance. The Clean Energy Regulator in Australia amended global warming potentials in August 2020. Therefore, the use of global warming potentials in our GHG calculations related to our Australian assets differs from the rest of our fleet. Applying harmonized global warming potentials across our fleet would result in a minor variance to our overall calculated GHG totals.

Our 2022 GHG data was 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.

The following tables detail our GHG emissions by scope, business segment and country in million tonnes of CO_2e. Some values do not sum to the indicated total due to rounding of tabulated emissions. Zeros (0.0) indicate truncated values.

Year ended Dec. 31	2022	2021	2020
Scope 1	**10.2**	12.4	16.3
Scope 2	**0.1**	0.1	0.1
Total GHG emissions	**10.2**	12.5	16.4

Year ended Dec. 31	2022	2021	2020
Hydro	**0.0**	0.0	0.0
Wind and Solar	**0.0**	0.0	0.0
Gas	**6.3**	6.5	7.7
Energy Transition	**4.0**	6.0	8.6
Corporate and Energy Marketing	**0.0**	0.0	0.0
Total GHG emissions	**10.2**	12.5	16.4

Year ended Dec. 31	2022	2021	2020
Australia	**0.9**	1.0	1.1
Canada	**5.2**	7.9	9.4
US	**4.1**	3.6	5.9
Total GHG emissions	**10.2**	12.5	16.4

In 2022, our GHG emissions (scopes 1 and 2) were 10.2 million tonnes as a result of normal operating activities. Compared to 2021, this represents a reduction of approximately 18 per cent or 2.3 million tonnes CO_2e. Because we sell the environmental attributes generated from our renewable energy facilities, we do not subtract this amount from our total emissions, but it should be noted that TransAlta's customers are reporting GHG emissions reductions using our renewable energy assets, projects and operations.

GHG emissions are verified to a level of reasonable assurance in locations in which we operate within a carbon regulatory framework. Any historical revisions to GHG data will be captured and reported in future disclosure. The majority of our GHG emissions result from carbon dioxide emissions from stationary combustion from coal and natural-gas-powered generation.

The following table highlights our scope 1 and 2 GHG emissions reductions since 2015 and our targeted emissions in 2026 (in line with our new GHG target). The actual GHG emissions for the Company in 2026 will vary from that presented below depending on, among other things, the growth of the Company, including its on-site generation business.

Year ended Dec. 31	2026 (forecast)	2022	2015
Total GHG emissions (million tonnes CO_2e)	**8.1**	**10.2**	32.2

Scope 3 Emissions
We estimate our scope 3 emissions in 2022 to be in the range of four million tonnes of CO_2e, which is primarily attributed to our non-operated joint venture interests.

Sustainable Finance

Sustainable finance is the process of taking due account of ESG considerations (e.g., climate change, biodiversity, human rights) when making investment decisions. Sustainable finance is a key pillar of TransAlta's Climate Transition Plan. This means we will utilize pools of capital available to sustainable economic activities and projects to finance our energy transition towards net-zero operations.

TransAlta deploys green and sustainable financing to build out our renewable energy fleet and advance our clean energy transformation. This supports our goal to deliver on our customers' needs for clean electricity. Since 2020, we have issued $703 million in green bonds and converted our four-year $1.3 billion revolving credit facility into a sustainability-linked loan.

In November 2022, TransAlta issued US$400 million ($533 million) in Senior Green Bonds, an amount equal to the net proceeds from the bonds will be used to finance or refinance new and/or existing eligible green projects. The bonds were issued under TransAlta's Green Bond Framework, which aligns with the Green Bond Principles published by the International Capital Market Association. For further details, refer to Public Offering and Pricing of US Senior Green Bonds and release of inaugural Green Bond Framework in the Significant and Subsequent Events section of this MD&A. In 2021, the Company's indirect wholly owned subsidiary, Windrise Wind LP, completed a secured green bond offering by way of private placement for approximately $173 million (face value).

In 2021, TransAlta converted an existing $1.3 billion syndicated revolving credit facility into a sustainability-linked loan. The loan aligns the cost of borrowing to the Company's GHG emissions reductions and gender diversity targets. Sustainability-linked loans are any types of loan instruments and/or contingent facilities (such as bonding lines, guarantee lines or letters of credit) that incentivize the borrower's achievement of ambitious, predetermined sustainability performance objectives.

The summary below shows the carrying value of the issued green bonds and the total facility size of our ESG financial operations portfolio.

As at Dec. 31 (in millions of Canadian dollars)	2022	2021	2020
Green bonds (1)	**703**	171	n/a
Sustainability-linked loans	**1,250**	1,250	n/a

(1) Green bonds are related to Senior Green Bonds issued in 2022 and the Windrise Wind green bond issued in 2021.

Climate-Related Financial Metrics

The results of TransAlta's 2021 climate-related scenario analysis, aligning with a 1.5°C warmer world, have shown that opportunities to grow the renewable fleet exist across all scenarios and locations. Our revenue from renewable energy generation (solar, wind and hydro) in 2022 was $1,014 million (2021 – $731 million) or 29 per cent of our total revenue in 2022.

We continue to execute the Clean Electricity Growth Plan to deliver 2 GW of new generation and a 5 GW growth pipeline by 2025 by reaching final investment decisions on 500 MW of additional clean energy projects across Canada, the United States and Australia in 2023. Our growth capital expenditures for renewable energy generation in 2022 was $666 million (2021 – $326 million).

As part of our Clean Electricity Growth Plan, our goal is to achieve 70 per cent of adjusted EBITDA from renewables and storage by the end of 2025. In 2022, adjusted EBITDA from renewable energy generation was $838 million (2021 – $584 million) or 51 per cent of our total adjusted EBITDA. Our renewable fleet makes our overall portfolio more resilient to climate-related risks, provides increased flexibility in generation and creates incremental environmental value through environmental attributes. Our revenue in 2022 from environmental attribute sales was $53 million (2021 – $40 million).

The disclosure of TransAlta's financial metrics related to our climate-related risks and opportunities align with the TCFD recommendations. A summary of our climate-related financial metrics is presented below.

Year ended Dec. 31 (in millions of Canadian dollars)	2022	2021	2020
Capital expenditures for renewable energy generation (1)	**666**	326	158
Renewable energy adjusted EBITDA (2)	**838**	584	353
Environmental attribute sales revenue (3)	**53**	40	25
Renewable energy adjusted revenue (4)	**1,014**	731	486

(1) Growth capital expenditures include amounts deployed for growth projects and acquisitions related to renewable energy generation. This includes the construction of our Windrise wind facility completed in November 2021, the acquisition of North Carolina Solar portfolio in November 2021, the construction of the Garden Plain wind project, White Rock wind projects, Horizon Hill wind project and Northern Goldfields solar project as part of our Clean Electricity Growth Plan. This excludes the Mount Keith transmission expansion project.
(2) Adjusted EBITDA from renewable energy generation includes hydro, wind, solar and battery storage facilities. These items are not defined and have no standardized meaning under IFRS. Refer to the Additional IFRS Measures and Non-IFRS Measures section of this MD&A.
(3) Environmental attribute sales revenue indicates the full amount of hydro, wind and solar environmental credits, without any other consolidation impacts.
(4) Adjusted revenue from renewable energy generation includes hydro, wind, solar and battery storage facilities.

Alignment with TCFD

The table below shows the alignment of our climate change management disclosure with TCFD recommendations.

Recommended Disclosures	Location
Governance	
Describe the board's oversight of climate-related risks and opportunities	Oversight by the Board of Directors
Describe management's role in assessing and managing climate-related risks and opportunities	Role of Senior Management
Strategy	
Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term	Key Scenario Findings
Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy and financial planning	Climate Change Strategy, Key Climate Scenario Findings
Describe the resilience of the organization's strategy, taking into consideration different climate-related scenarios, including a 2°C or lower scenario	Climate Scenarios, Key Climate Scenario Findings
Risk management	
Describe the organization's processes for identifying and assessing climate-related risks	Climate Change Strategy
Describe the organization's processes for managing climate-related risks	Managing Climate Change Risks and Opportunities
Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall risk management	Managing Climate Change Risks and Opportunities
Metrics and targets	
Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process	Climate Change Metrics and Targets
Disclose scope 1, scope 2 and, if appropriate, scope 3 greenhouse gas (GHG) emissions and the related risks	Climate Change Metrics and Targets
Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets	Climate Change Metrics and Targets

Enabling Innovation and Technology Adoption

Technology and innovation are an existing and increasing focus at TransAlta. We have long been innovators. 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. In 2015, we made our first investment in solar technology in Massachusetts and, in 2020, we installed the first utility-scale battery in Alberta. We are now looking to advance a new technology roadmap that aligns with the Clean Electricity Growth Plan. This section covers manufactured and intellectual capital management as per guidance from the International Integrated Reporting Framework.

Our Energy Innovation Team

As part of our Clean Electricity Growth Plan, in 2021, we established an Energy Innovation team to investigate, prioritize and deploy new net-zero electricity generation technologies that address the four pillars of our business: affordability, reliability, safety and non-emitting. As we grow our renewables business, the Energy Innovation team is focused on what we should build next that complements our wind, solar and hydro assets to deliver reliable, affordable and clean electricity to our customers. At the same time, the Energy Innovation team is looking at electrification broadly to investigate where potential new, adjacent business opportunities may exist for TransAlta.

Renewable Energy

Today, we operate 944 MW of hydro energy, 1,906 MW of wind and battery storage, and 143 MW of solar power. We continue to look for opportunities to develop and operate solar energy.

In 2022, TransAlta executed a long-term renewable energy PPA with a subsidiary of Meta for 100 per cent of the generation from its 200 MW Horizon Hill wind project located in Oklahoma. Under this agreement, Meta will receive both renewable electricity and environmental attributes from the Horizon Hill wind project. The facility will consist of a total of 34 Vestas turbines. Construction commenced in the fall of 2022 with a target commercial operation date in the second half of 2023.

We also entered into a long-term PPA for the remaining 30 MW from our 130 MW Garden Plain wind project, to be located in Alberta. We will deliver renewable electricity and environmental attributes to a new investment-grade globally recognized customer. In 2021, TransAlta entered into a long-term PPA with Pembina Pipeline for the offtake of 100 MW from our Garden Plain wind project. The project began in 2021 and is expected to achieve its commercial operation date early in 2023.

In 2022, TransAlta identified Amazon as the customer for the 300 MW White Rock wind projects, to be located in Oklahoma. In 2021, we entered into two long-term PPAs with Amazon for the offtake of 100 per cent of the generation from the projects. Construction activities started in the fall of 2022 with a target commercial operation date in the second half of 2023.

In 2021, TransAlta acquired a 122 MW portfolio of operating solar sites located in North Carolina, which represented a significant expansion of our solar generation. We intend to further expand our solar generation by actively pursuing solar opportunities in the US and Australian markets. The Company is also focused on pursuing hybrid integrated power solutions with customers.

In 2021, TransAlta agreed to provide renewable solar electricity supported with a battery energy storage system to the Goldfields-based operations of BHP Nickel West through the construction of the Northern Goldfields solar project in Western Australia. The project consists of the 27 MW Mount Keith solar facility, 11 MW Leinster solar farm and 10 MW/5 MWh Leinster Battery Energy Storage System and interconnecting transmission infrastructure, all of which will be integrated into TransAlta's 169 MW Southern Cross Energy North remote network. The Northern Goldfields solar project is expected to reduce BHP's scope 2 electricity GHG emissions from its Leinster and Mount Keith operations by 540,000 tonnes of CO_2e over the first 10 years of operation. Construction of the project commenced in early 2022 and commercial operations are targeted in the first half of 2023.

TransAlta is actively advancing its development pipeline. In 2022, the Company announced 200 MW of new build projects. TransAlta has established a pipeline of potential growth projects that includes 374 MW of advanced stage development projects along with 3,891 to 4,991 MW of projects in earlier stages of development.

Scaling Up Energy Solutions

Battery Storage

We continue to invest in battery storage. In 2020, we commissioned WindCharger, 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.

The Northern Goldfields solar project in Western Australia will provide both renewable solar electricity and a battery energy storage. The energy storage consists of the 10 MW/5 MWh Leinster Battery Energy Storage System which will be integrated into TransAlta's remote network. The network and new generation will support BHP Nickel West to meet its emissions reduction targets and deliver lower-carbon, sustainable nickel to its customers.

Future Solutions

Hydrogen

In February 2022, we announced a $2 million equity investment in Ekona’s Series A funding round. The investment will help support the commercialization of Ekona’s novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. If successful, Ekona’s distributed technology allows for onsite production of hydrogen, avoiding the need for costly transportation of hydrogen, and its solid carbon byproduct allows for low-cost, low-emissions hydrogen production without the need for carbon sequestration. TransAlta is a member of Ekona’s Strategic Committee and will continue to work with Ekona as it develops its pyrolysis technology.

Nature-based Solutions (NBS)

Nature-based Solutions are actions to protect, sustainably manage and restore natural and modified ecosystems that address societal challenges effectively and adaptively, simultaneously benefiting people and nature. TransAlta is actively evaluating NBS as carbon removals to neutralize any limited emissions that we cannot yet eliminate.

Direct Air Capture (DAC)

Direct air capture (DAC) technologies extract CO_2 directly from the atmosphere. The CO_2 can be permanently stored in deep geological formations, thereby achieving permanent CO_2 removal. TransAlta continues to explore the benefits of DAC as a carbon dioxide removal option to support the net-zero transition of our operations and customers.

Carbon Capture, Utilization and Storage (CCUS)

Our teams continuously explore the use of applied or new technologies such as CCUS to reduce GHG emissions. 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.

Disruptive Technologies

In May 2022, we entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners' ("EIP") Deep Decarbonization Frontier Fund 1 (the “Frontier Fund”) that will invest in early-stage, innovative technology companies that will accelerate the transition to net-zero GHG emissions. TransAlta's investment in the Frontier Fund provides TransAlta with the opportunity to pool funds with some of the largest utilities in the United States and Europe to identify, pilot, commercialize and bring to market technologies that will support its decarbonization goals. For more information, refer to Energy Impact Partners ("EIP") Investment in the Significant and Subsequent Events section of this MD&A.

Fusion

Fusion technologies attempt to recreate the fusion reactions in the sun by fusing two hydrogen molecules together. If successful, fusion promises low-cost energy, with far shorter-lived nuclear waste. Fusion achieved some significant development milestones in 2022, including most significantly, Lawrence Livermore National Laboratory achieving net energy gain. This, coupled with unprecedented capital flow into fusion companies, has led to newfound excitement that fusion may be able to leapfrog current generation technologies.

Through EIP, TransAlta has developed a partnership with ZAP Energy, a leading fusion start up. ZAP Energy’s technology stabilizes the hydrogen plasma using sheared flow (driving current through the flow creating the magnetic field confining and compressing the plasma) rather than magnetic fields. In September 2022, ZAP announced it will conduct a feasibility study of retrofitting the former TransAlta Big Hanaford gas plant located in Centralia to host its first-of-a-kind Z-pinch fusion pilot plant. ZAP received $1 million from the Centralia Coal Transition Grants Energy Technology Board as part of our energy transition investments to move away from coal in Washington State.

Idea Generation and Innovation

Idea Generation

Our Rise (formerly known as the "Greenlight") program continues to be a driving force behind the strong culture of idea generation and problem solving at TransAlta. The program emphasizes bottom-up innovation, which means business improvement ideas are generated by employees. These ideas are developed and advanced into business cases, adhering to best practices of project management, to ensure successful implementation of the improvement opportunity. From the initial ideation, to development and delivery, this process is driven entirely by employees, with support from leaders across the organization.

Supplier Innovation

Another initiative we promote is the TransAlta Innovation Series. The series aims to empower our workforce through relevant industry knowledge on innovative concepts. This includes bringing in thought leaders on new technologies to discuss conceptual ideas that initiate creative thinking and suppliers that provide insight into commercial applications of evolving technologies. The series continually advocates TransAlta’s value and organizational culture of innovation and learning. The series focuses on informing our employees on the different kinds of innovative concepts and technologies developing in our industry that they can bring forward in the organization, while also developing relationships with leading-edge companies. In 2022, the series also sponsored several charities that have either benefited from the technologies being discussed or are charities the speaker’s support on behalf of their organization’s ESG and ED&I initiatives.

In 2022, we delivered eight sessions across four different categories, including energy innovation, operational innovation, digital innovation and innovation mindset. Under energy innovation, we looked at the evolution of ESG going from a functional requirement a few years ago to currently becoming a core value driver in corporations. We learned about the up-and-coming role that nuclear small modular reactors will play nationally and internationally. We also had one of our customers participate in a fireside chat to discuss how the partnership with TransAlta is providing clean power solutions and impacting the clean energy transition. Under operational innovation, we discussed what the future of meetings will look like in a hybrid workplace and the importance of a customer-centric shared services’ business model. Our digital innovation presentations looked at safety and health apps for our frontline workers and how geospatial intelligence could be used to optimize and transform the utilities industry. Finally, the presentation focusing on developing an innovation mindset looked at the periodic table of innovation where all innovation is categorized into 10 main types and how we can use these as tools to further our own creativity.

Analytics and Automation

Asset Analytics and Optimization

TransAlta's Asset Analytics and Optimization (“AAO”) team was founded in 2008. This team monitors coal-fired steam, gas-fired steam, simple-cycle, combined-cycle/cogeneration and wind-generating assets across Canada, the US and Australia. A centralized team of engineers and operations specialists remotely monitors our power facilities for emerging equipment reliability and performance issues. The AAO team also performs production reporting functions for these assets and is actively engaged in projects to improve this reporting.

AAO staff are trained in the development and use of specialized equipment monitoring and performance assessment software and they apply their experience to power facility operations. If an issue is detected, the AAO will initially assess and then notify facility operations of their findings to support investigation and remedy of the issue before there is an impact to operations. This support is critical for reliability and performance of our operations. For example, if a wind turbine starts to show very early signs of equipment change 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 AAO are focused on early identification of equipment issues based on longer-term trend analysis and complements day-to-day facility operations.

Automation and Robotics

TransAlta created the Data and Innovation team in 2019 to modernize its data infrastructure and take advantage of new opportunities in analytics and data science. The Data and Innovation team is cross-functional; composed of data architects, data engineers, data analysts, software developers, integration specialists and engineers. The team focuses on the delivery of value using digital innovation, such as the modernization of data management strategy and platforms, the rapid delivery of data-driven applications, the design and implementation of advanced analytics and machine learning models and the execution of robotic process automation to eliminate manual tasks.

A few highlights from this work in 2022 include:

- The Data and Innovation team worked with partners across the company to advance its Asset Performance Management platform, GenOS, to deliver new features that increase the performance and management of our renewable asset fleet. Key process improvements, such as enhanced performance analytics that leverage machine learning, advanced analytics and data science models, provide our operators with deeper insights to help optimize asset performance across the entire fleet. Built in-house, GenOS provides data-driven insights for our wind, solar, gas and hydro fleets.
- The substantial growth of our Advanced Automation Program has increased the number of manual processes we have automated, allowing our subject matter experts to spend more time on higher-value opportunities. With industry leaders in automation, TransAlta is able to leverage high impact technology to quickly develop custom robotic process automations across the company.
- Continued engagement 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. The 2022 cohort worked on six cases including component health monitoring for our wind and solar fleet forecasting models.
- With a focus on the future, the Data and Innovation team kicked off the Digital TransAlta Program to identify and plan for the core business capabilities required to respond to a changing industry and technology landscape over the next five years. This program looks to match digital innovation with key areas of opportunity across our Operations, Growth, Corporate and Trading teams. In 2022, we delivered ideation sessions across the company and with industry partners.

Drones

In April 2022, TransAlta formed the Robotics Inspection Council. The Council's purpose is to coordinate and assess the use of drones for robotic inspections to increase value to the business through improved safety, reduced inspection costs and better communication. In alignment with TransAlta’s core value of safety, the Council defined the corporate requirements on the safe use of remotely piloted aircraft in TransAlta's fleet. The Council also met with vendors and industry peers to understand areas of opportunity and how these technologies are being deployed. Robotic inspections were performed in TransAlta’s gas and hydro fleets. The Council is investigating additional applications in our renewable fleet for 2023.

Engaging with Our Stakeholders to Create Positive Relationships

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 fostering positive relationships with Indigenous neighbours, communities, stakeholders, governments, industry and landowners in the areas where we operate, as well as public health and safety. This section covers sustainability factors of social and relationship capital and intellectual capital as per guidance from the International Integrated Reporting Framework.

Inclusive Transition

In support of our energy transition, since 2015, TransAlta has been investing US$55 million over 10 years to support energy efficiency, economic and community development and education and retraining initiatives in Washington State. The investment is part of the TransAlta Energy Transition Bill passed in 2011. This bill was a historic agreement between policymakers, environmentalists, labour leaders and TransAlta to transition away from coal in Washington State by closing the Centralia facility’s two units, one in 2020 and the other in 2025. Three funding boards were formed to invest the US$55 million: the Weatherization Board (US$10 million), the Economic and Community Development Board (US$20 million), and the Energy Technology Board (US$25 million). To date, the Weatherization Board has invested US$9.5 million, the Economic and Community Development Board US$15 million and the Energy Technology Board US$15 million.

Specific projects that the boards funded in 2022 include a grant to Twin Transit in support of the installation of Southwest Washington’s first Containerized Green Hydrogen Electrolyzer at the Port of Chehalis, providing a reliable source of local hydrogen and proximity to the market; financial support to the Formic Liquid Hydrogen Carrier Clean Energy Demonstration Project at the Port of Tacoma and other locations in the state of Washington, an initiative to replace the use of fossil fuels in the refrigeration of cargo containers; and funding to support solar systems for organizations and non-profits in Washington.

Additionally, in 2016, TransAlta announced that we had reached an agreement with the Government of Alberta for the cessation of coal-fired emissions from coal-fired electricity generation facilities in Alberta (Off-Coal Agreement). As part of the Off-Coal Agreement, TransAlta has invested in programs and initiatives to support the communities surrounding the plants negatively impacted by the phase-out of coal generation during the transition.

Customers

TransAlta serves industrial and commercial customers with power and energy services across its fleet in Canada, the US and Australia. We are focused on customer-centred renewables growth to bring high levels of service quality and reliability for our customers in a low-carbon future. As one of the largest electricity generators in Canada, our team serves businesses with:

- Sustainable solutions starting from the design phase;
- Energy consumption and cost management solutions;
- Market price risk and volume exposure mitigation; 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. Our work has been recognized by our customers through an average retention rate of 88 per cent over the last three years.

Across our business in Canada, the US and Australia, 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. We continue to explore opportunities to provide 24/7 carbon-free energy to help customers meet their decarbonization goals.

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 emissions reduction targets. Production from renewable electricity in 2022 resulted in the avoidance of approximately 2.7 million tonnes of CO_2e for our customers.

Our experience in developing and operating low-carbon power facilities is highlighted below:

Power generation type	Operating experience (years)
Hydro	111
Natural Gas	72
Wind	25
Solar	8
Battery Energy Storage Systems	2

For further details on how we support our customers' sustainability objectives, please refer to the Enabling Innovation and Technology Adoption section of this MD&A.

Human Rights

TransAlta is committed to honouring domestic and internationally accepted labour standards and supports the protection of human rights of all its employees, contractors, suppliers, partners, Indigenous partners and other stakeholders. We abide by human rights and modern slavery legislation in Canada, the US and Australia. 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 have governance practices in place for the protection of human rights.

Our Human Rights and Discrimination Policy communicates our commitment to human rights in our operations and supply chain to ensure that our personnel policies and practices in our global operations respect fundamental rights. Expected behaviours of all our employees are set out in our Corporate Code of Conduct. We are committed to creating a work environment where all workers feel safe and are valued for the diversity they bring to our business. Our annual mandatory Code of Conduct training is required for employees to complete before signing the Code of Conduct. We also have adopted a Supplier Code of Conduct that defines the principles and standards expected of suppliers, their employees and contractors to meet while providing goods and/or services to TransAlta.

Our Whistleblower Policy provides a mechanism for our employees, officers, directors and contractors to report, among other things, any actual or suspected ethical or legal violations. We would seek to remedy the impact promptly in order to establish a corrective action plan in collaboration with the relevant individuals and stakeholders.

In Australia, we report under the Australian modern slavery legislation. Our Modern Slavery Act Statements demonstrate the actions we have taken to assess and address modern slavery risks within our operations and supply chain. These annual statements are approved by our Board of Directors and are publicly available.

Supply Chain and Sustainable Sourcing

We continue to seek solutions to advance supply chain sustainability. 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 and for select procurement engagements, 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.

Supply chain is a pillar of our Clean Electricity Growth Plan to deliver net-zero operations. We have enhanced the supplier management functionality within our corporate procurement system and are working to incorporate ESG data reporting capability. In the next few years, we will develop ESG criteria for supply chain engagement and work to understand our direct suppliers' GHG emissions profile and targets. Our long-term plan is to engage with suppliers to explore enhancement of their GHG emissions targets and set direction for engaging suppliers with GHG emissions reduction targets.

In 2022, TransAlta approved a new goal to integrate sustainability into supply chain. Our target is "By 2024, 80 per cent of our spend will be with suppliers that have a sustainability policy or commitment". This supports the intent of the UN SDG Target 12.7: “Promote public procurement practices that are sustainable, in accordance with national policies and priorities.”

Our Supplier Code of Conduct 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.

Indigenous Relationships and Partnerships

At TransAlta, we value relationships and partnerships with our Indigenous neighbours, aspiring to the highest standards in our relationships with Indigenous peoples. Our core values of safety, innovation, sustainability, respect and integrity represent how we do business and engage with Indigenous peoples. Our commitment to Indigenous relations is led by a centralized corporate team who foster a relationship-based approach, involving employees at our facilities and within each business unit. These employees and teams build relationships with the neighbouring Indigenous communities and work to develop respectful, trusting relationships that help TransAlta continually improve its business practices.

Our Indigenous Relations Policy focuses on five key areas: community engagement and consultation, business development, community investment, employment, and training and awareness. We ensure that TransAlta's principles for engagement are upheld and the Company fulfils its commitments to Indigenous communities. Efforts are focused on building and maintaining solid relationships and 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 and unlock opportunities.

Methods of engagement include:

- Relationship building through regular communication and meetings with representatives at various levels within Indigenous communities and organizations;
- Hosting company-community activities to share both business information and cultural knowledge;
- 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 takes a proactive approach in engagement by initiating communication early in project development to allow concerns to be identified and addressed, which has minimized potential project delays. We strive to maintain relationships through the life cycle of our operations, from project development and construction, through operation, until decommissioning phases are complete. We work with communities to build relationships based on a foundation of ongoing communication and mutual respect. This is recognized in our Indigenous Relations Policy, which was recently updated to include our acknowledgement and understanding of the intent of the recommendations of the United Nations Declaration on the Rights of Indigenous Peoples.

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 move forward to become future leaders in their communities. We are keen to help young Indigenous students reach their full potential and achieve their dreams. We also believe in providing support to Indigenous primary school students, helping to instil a passion for lifelong learning.

In 2022, TransAlta provided more than $457,000 to support Indigenous youth, education and employment programs, representing 20 per cent of TransAlta's total community investment. Highlights include:

- **Mother Earth's Children's Charter School ("MECCS")** – Located in Treaty 6 territory, Alberta, 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 student population is diverse and includes Métis, Cree, Nakoda Sioux and Stoney. Volunteers from TransAlta travel to the school to deliver Christmas gifts, providing both our employees and the students the opportunity to engage with each other.
- **Spirit North** – TransAlta is proud to support Spirit North, a national charitable organization that uses land-based activities to improve the health and well-being of Indigenous youth. Through the transformative power of sport and play, participants learn important lessons, discover untold potential and build the confidence and courage needed to overcome the hardships Indigenous youth often face.
- **The Read On Literacy Program** – In 2022, TransAlta supported the development of an Indigenous literacy program that seeks to mentor young people in First Nation schools to achieve their maximum academic, personal and social development by promoting the core values of education, literacy, taking pride in ones' culture and making good decisions in one's life. TransAlta has sponsored the Read On Literacy Program to provide this initiative to elementary students in Alberta in 2023.
- **Books In Homes** – Funding supports an early literacy program for the children of Tjiwarl Aboriginal Corporation members in Western Australia.

Indigenous Cultural Awareness Training for TransAlta Employees

In 2021, we adopted a new sustainability target that will see all employees complete Indigenous cultural awareness training by the end of 2023. We believe education is the foundation to ensuring respectful and strong relationships with Indigenous peoples into the future. In 2022, 100 per cent of Canadian employees have completed Indigenous cultural awareness training. Our employees in the US and Australia will receive the training in 2023.

Stakeholder Relationships

Fostering positive relationships with our stakeholders is important to TransAlta. Driven by our core values, we see stakeholder transparency as an integral part of our relationships. We take a proactive approach to building relationships and understanding the impacts our business and operations may have on local stakeholders.

Our Stakeholders

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

- Build relationships through regular engagement with stakeholders regarding 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 and prospective project development or acquisition. Through decades of establishing stakeholder relationships in the areas of our facilities, we have developed a strong knowledge of who our stakeholders are and gained understanding of our stakeholders' issues and concerns.

Our principal stakeholder groups are listed in the following table.

TransAlta stakeholders		
Non-governmental organizations	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 and gas associations/Industry	Railroad owners
Customers	Think tanks	Utility owners
Municipalities	Academics	Employees

Stakeholder Engagement

In order to run our business successfully, we maintain open communication channels with our stakeholders. We are committed to timely and professional resolution in our dialogue with stakeholders. Our stakeholder engagement practices are guided by regulatory requirements, industry best practices, international standards and corporate policies. We work internally and with each stakeholder to identify and mitigate further issues.

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

Information and communication	Dialogue and 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 and attending events

A key focus of our work is to support business growth through proactive engagement with stakeholders in our geographic operating areas in Canada, the US and Australia to develop and maintain relationships, assess needs and fit and seek out collaborative and sustainable 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 construction and maintain engaged communication throughout operations to decommissioning.

Examples of stakeholder engagement in 2022 include: the WaterCharger battery energy storage project virtual open house, Highvale Mine decommissioning and reclamation plan public open house, Tempest wind project public open house, virtual stakeholder meeting on the Bow River management with local stakeholders and recreational users and the Kent Hills rehabilitation plan.

Community Investments

In 2022, TransAlta contributed approximately $2.3 million in donations and sponsorships (2021 – $3.0 million), with a continued focus in three priority areas: youth and education, environmental leadership and community health and wellness.

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 Company raised over $1.2 million for the United Way. TransAlta has been supporting the United Way for over 30 years and has contributed more than $22 million over that time.

In 2022, TransAlta made a number of other significant investments, including the following highlights:

- **Calgary Health Foundation** - In 2022, TransAlta announced a $2 million contribution to the Calgary Health Foundation to support the Newborn Needs campaign in support of the development of a new Foothills Medical Centre Neonatal Intensive Care Unit, serving all of southern Alberta.
- **Foodbank Support** – In December 2022, TransAlta donated $250,000 to local food banks near our operating assets in Canada, the US and Australia. This initiative recognizes the hardship faced in many communities and the increased reliance on food banks as families struggle to make ends meet.
- **Centralia College** - TransAlta (through the Centralia Coal Transition Board) invested $1.3 million in the Southwest Washington Flexible Training Center, located at the Centralia College campus. The center is a 12,000 square foot facility that will expand the college’s ability to train-on-demand in response to and in anticipation of industry needs.

Public Health and Safety

We are committed to protecting the public and our assets, as well as the physical, psychological and social well-being of our employees.

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 the protection of people, property, information and reputation.

The Corporate Emergency Management Program prepares employees should an emergency incident occur. The program receives executive sponsorship and includes an emergency management policy and standard, which sets an expectation for employees to continuously prepare for emergencies. 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 and 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 the Company throughout the response and recovery, ensure all messaging is approved by the Incident Commander, 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 diligently 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. 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 through this program.

TransAlta complies with the North American Electric Reliability Corporation Critical Infrastructure Protection ("NERC CIP") requirements. The NERC CIP is a set of standards aimed at regulating, enforcing, monitoring and managing the security of the North American power system. These standards apply specifically to cybersecurity risks.

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

Building a Diverse and Inclusive Workforce

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. In 2022, we improved our ESG performance through our efforts to promote an equitable, diverse and inclusive workforce. This section covers sustainability factors of human capital as per guidance from the International Integrated Reporting Framework.

Equity, Diversity and Inclusion

TransAlta's commitment and focus on excellence in ED&I is found in our workplace, among our co-workers who advocate for the values of equity and inclusion at all working levels. This commitment is outlined in our Board and Workforce Diversity Policy and Diversity and Inclusion Pledge. We believe a strong focus on ED&I will create a culture of belonging, allowing our employees to bring their authentic selves to work where they can thrive, innovate, improve service to our customers and positively impact the communities that we live in.

In 2022, TransAlta executed the second year of our five-year ED&I strategy to achieve the goals and aspirations defined in our ED&I Pledge.

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, 2022, women made up 30 per cent of our executive officer team and 36 per cent of our Board. These percentages are higher than the Canadian corporate averages of board seats held by women (24 per cent) and women on executive teams (21 per cent), according to data from all disclosing Canadian TSX-listed companies in Canada.

To further support female advancement, we have set targets to: (i) maintain equal pay for women in equivalent roles, (ii) achieve 50 per cent representation of women on our Board by 2030 and (iii) achieve 40 per cent representation of women among all employees by 2030. Currently, women employees represent 26 per cent of all employees. Though the majority of our operational roles are currently held by male employees, we remain committed to achieving the 40 per cent goal in this time period.

TransAlta was once again added to the Bloomberg Gender-Equality Index in 2022. 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 2022, the Company received the Globe and Mail's Women Lead Here award, which evaluates publicly traded Canadian companies' ratio of female-identifying to male-identifying executives in the top three tiers of executive leadership.

In 2022, we continued with the Women in Trades Scholarship with 13 different educational institutions for eligible students enrolled in post-secondary trade programs. In 2022, we also continued with a female apprenticeship program in our Generation business to strategically target the recruitment of female students and train them to gain valuable experiential learning in the trades.

Workforce Health and Safety

The safety of our people, communities and the environment is one of our core values. Our focus on Operational Excellence puts into action TransAlta's value of enabling a safe environment for our people and our communities. Operational Excellence is about powering and empowering our communities in a safe, environmentally friendly and sustainable manner by investing in clean electricity generation and ensuring our assets operate reliably and efficiently.

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.

We made significant progress on our safety culture transformation journey. Training and development initiatives were a top priority in which we completed behaviour-based safety training for all employees. This training provides the tools and strategies to allow employees to influence their individual behaviours and encourage personal ownership over safety outcomes. It helps create a psychologically safe environment in our workplace as it encourages personal accountability towards safety.

One of our key safety indicator is the Total Recordable Injury Frequency ("TRIF"). TRIF tracks the number of injury incidents that require treatment beyond first aid, relative to total exposure hours worked. Our TRIF result for 2022 was 0.39 compared to 0.82 in 2021. In 2022, our TRIF exceeded the target of 0.61 and was our best annual result on record. To put this into perspective, we had six recordable injuries in 2022 compared to 17 in 2021. We had zero lost-time injuries or restricted work injuries.

In part, our strong safety performance can be attributed to the extensive work we have done to support our three key strategies: mature our safety culture, assess and address risk tolerance and standardize safety information and technology. To sustain and enhance our safety culture, TransAlta conducted more than 100 one-hour peer board sessions for leaders across the fleet. These sessions reinforce the concepts learned in behaviour-based safety training and provide leaders with key safety information to share with their teams.

The following represents our corporate safety performance and includes employees and contractors:

Year ended Dec. 31	2022	2021	2020
Lost-time injuries	**0**	3	5
Medical aids	**6**	9	9
Restricted work injuries	**0**	5	2
Exposure hours	**3,058,000**	4,134,000	3,948,000
Total Recordable Injury Frequency (TRIF)	**0.39**	0.82	0.81

We also focus on Total Safety Report Frequency. 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. We also report and recognize positive behaviours in the workplace to enable a safe environment. This allows us to not only manage incidents when they occur but identify opportunities to prevent them from occurring in the first place. In 2022, we recorded 12 reports per worker, which is well above our threshold target of 10. Evidence of the positive impacts associated with strong reporting is apparent when looking at our overall safety performance. As a demonstration to TransAlta's commitment to safety, SunHills Mining LP was awarded the Safety Excellence Award from the Alberta Mine Safety Association in June 2022. This award is for best safety performance of all Alberta mines under one million workforce hours based on 2021 performance. In 2022, our Gas segment teams also celebrated one year with no lost-time, medical aid or restricted work injuries.

Organizational Culture and Structure

Our employees are central to value creation. Our corporate culture has evolved and adapted throughout our 111-year history. Our values are safety, innovation, sustainability, respect and integrity. These five 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.

Culture Transformation

In 2022, we embarked on our culture transformation journey with our goal of becoming a culture of learning, purpose and results. We developed a three-year culture strategy, Culture Charter and Culture Roadmap that defines milestones. For alignment and transparency, all of these documents are available to our employees.

We launched an Employee Engagement Survey to gauge the employee experience, and based on survey results, leaders created action plans to drive improvement and increase engagement at the business unit and team level.

Finally, we are focused on employee well-being. To increase awareness, we have launched education sessions on a variety of topics such as mental health, women's health, men's health, nutrition, resiliency, etc.

Organizational Structure

As of Dec. 31, 2022, we had 1,222 (2021 – 1,282) active employees. This number has decreased by five per cent from 2021 levels, following a reduction in positions in our coal fleet as part of our conversions to gas and cessation of mining operations. With approximately 31 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.

Our organizational structure remained the same in 2022. Our business operates four generating segments, with Gas, Wind and Solar, Hydro and Energy Transition. In addition, our Alberta Business Unit and Energy Marketing Team optimize our asset fleet while managing commodity exposures. Our Corporate segment, including finance, legal, human resources, administrative, business development and investor relations functions, oversees our business and provides strategic alignment. The Company also includes a Shared Services division that oversees our information technology, supply chain, 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.

Employee Retention and Recognition

ESG-Linked Compensation

At TransAlta we have linked our ESG performance to our employees' compensation, including that of our executive leadership team. Our annual and long-term incentive pay for performance plans are linked to TransAlta reaching various ESG goals, the targets and metrics of which are reviewed and approved annually by our Board of Directors.

In 2022, 20 per cent of our annual incentive plan was linked to achieving specific ESG objectives: five per cent related to our equity, diversity and inclusion score, five per cent referred to our organizational culture improvements and 10 per cent was linked to safety. Further, 30 per cent of our annual incentive plan was tied to growth, which is focused on expanding TransAlta's portfolio of renewable generation and will help reduce the Company's overall GHG emissions intensity. Our long-term incentive plans include strategic goals related to our focus on clean electricity, strong renewables growth, leading in ESG policy development, delivering on our culture plan and our ED&I strategy. Refer to the Management Proxy Circular for additional details on our ESG related compensation.

Employee Performance and Recognition

We strive to be an employer of choice through our total rewards programs, which include pay-for performance incentive plans, as reviewed and approved by the Board of Directors. TransAlta's annual and long-term incentive plans are designed to measure and recognize employees' contributions towards metrics and targets. In order to motivate and engage employees in a timely manner, we have implemented select employee recognition programs, including a quarterly recognition program and a peer-to-peer recognition program.

Talent Development

TransAlta places significant focus on talent development and retention of its employees. Annually, employees complete a combination of mandatory, optional and bespoke training as part of their roles. All employees have access to speakers who are experts on topics as varied as ED&I, mental health, culture, soft skills development and financial wellness.

Progressive Environmental Stewardship

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. This section covers natural capital management as per guidance from the International Integrated Reporting Framework.

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 during our clean electricity transition. Our environmental management processes support our corporate strategy of ceasing GHG-intensive coal operations. In 2026, our generation mix will be made up of natural gas and renewable energy only, with a goal of 70 per cent of EBITDA from renewables.

Environmental Policy

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. Our new Environmental Policy defines how we are integrating the protection of nature and the environment within TransAlta's strategy, Total Safety Management System, as well as the principles of conduct for the management of natural resources.

Environmental Management System

At TransAlta, we operate our facilities in line with best practices related to environmental management standards. Our environmental management processes are verified annually to ensure we continuously improve our environmental performance. Our knowledge of environmental management systems ("EMS") has matured since we aligned our processes in accordance with the internationally recognized ISO 14001 EMS standard. Currently, the most material natural or environmental capital impacts to our business are GHG emissions, air emissions (i.e., pollutants) and energy use. Other material impacts that we manage and track performance on via our environmental management practices include land use, water use and waste management.

In addition to our environmental management practices, 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 Company'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 Company. We interact with a number of regulators on an ongoing basis.

Environmental Performance

Our performance on managing environmental aspects, reducing our environmental impact and capitalizing on environmental initiatives includes the following:

Biodiversity

The importance of environmental protection and biodiversity is outlined in our new Environmental Policy as a corporate responsibility for TransAlta and a responsibility of each employee and contractor working on TransAlta's behalf. In 2022, the Company approved two new sustainability goals for the protection of nature and biodiversity. For further information, refer to the 2023+ Sustainability Targets section of this MD&A.

Overseeing Biodiversity-Related Issues

TransAlta's GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of environmental regulations, public policy changes and the development of strategies, policies and practices for the environment. For further information, refer to the Sustainability Governance section of this MD&A.

Assessing Biodiversity Impacts of Our Value Chain

We consider the biodiversity impact at all of our existing operations (a greater focus has been 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 health. Details on how we assess biodiversity impacts of our value chain are presented in the sections below.

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 strategies 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. Typically, our renewable projects are greenfield development projects that require a higher level of evaluation compared to our gas projects, which integrate into existing industrial facilities.

In addition, each greenfield development project has a detailed community engagement 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, resolving and mitigating stakeholder or Indigenous community concerns before filing major permit applications for all of our projects.

Day-to-day Operations
At our Alberta operations, in 2022, we continued with our 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 with facility approvals. We continue to work toward operational improvement and regularly review our Environmental Operational Management Plans to ensure our operating parameters are met.

At our wind and solar operations, an Operational Environmental Management Plan has been developed for each asset to ensure that our facilities use environmentally sound and responsible practices that are based on a philosophy of continuous improvement of environmental protection. Examples of environmental initiatives to support our biodiversity focus include our bird and bat protection practices (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), and long-term dataset collections (e.g., wildlife studies pre-construction and post-construction). In addition, we continue to collaborate with industry and the scientific community to address environmental concerns and impacts pertaining to biodiversity.

At our Centralia operations, in 2022, we built a riparian reforestation strategy for under-forested areas along the Skookumchuck River within our Skookumchuck Wildlife Habitat Management Area. Approximately 40 acres will be restored in 2023 with conifer-dominated forest types along both sides of the river. This will improve ecological functions important to river habitat including shade, sediment filtration, large woody debris input, nutrient input and bank stabilization. In addition, we planted 1600 trees in the Chehalis Basin Wetland Mitigation Bank and completed a vigorous weed control program to control reed canary grass and invasive/noxious weeds.

Energy Use

TransAlta uses energy in a number of different ways. We burn natural gas, diesel and coal (to 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.

The following captures our energy use (million gigajoules). Energy use decreased by four (4) per cent in 2022 over 2021. Some values do not sum to the indicated total due to rounding. Zeros (0) indicate truncated values:

Year ended Dec. 31	2022	2021	2020
Hydro	**0**	0	0
Wind and Solar	**0**	0	0
Gas	**130**	118	138
Energy Transition	**64**	86	141
Corporate and Energy Marketing	**0**	0	0
Total energy use (million gigajoules)	**195**	204	279

Air Emissions

Our coal facility emits 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 continue reducing air emissions in our existing facilities through our conversion and retirement of coal units in Alberta (completed in 2021) and Washington State (planned completion by the end of 2025).

In 2022, we achieved our 2026 target of 95 per cent SO_2 and 80 per cent NO_x emissions reductions over 2005 levels. Since 2005, we have reduced SO_2 emissions by 98 per cent and NO_x by 83 per cent. By the end of 2025, mercury emissions will be eliminated following the planned retirement of the Centralia remaining unit. Particulate matter and SO_2 emissions will also be virtually eliminated or considered negligible.

None of our previous Alberta coal facilities are located within 50 kilometres of dense or urban populations and they all have been retired or converted to gas as of 2021. 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, Fort Saskatchewan and Ada gas facilities are our facilities with air emissions within 49 kilometres of dense or urban environments.

Our total air emissions in 2022 decreased compared with 2021 levels. Specifically, NO_x was reduced 21 per cent, particulate matter was reduced 82 per cent and SO_2 was reduced 86 per cent over 2021 levels. Mercury emissions also decreased by 50 per cent over 2021 levels. Reductions in emissions were primarily due to shutdowns during coal-to-gas conversions and coal unit retirements.

The following represents our material air emissions. Figures have been rounded to the nearest one thousand with the exception of particulate matter (rounded to the nearest one hundred) and mercury (rounded to the nearest ten):

Year ended Dec. 31	2022	2021	2020
SO_2 (tonnes)	**1,000**	7,000	12,000
NO_x (tonnes)	**11,000**	14,000	21,000
Particulate matter (tonnes)	**400**	800	4,000
Mercury (kilograms)	**20**	40	60

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 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.

Our water consumption reduction target is to reduce fleet-wide water consumption (withdrawals minus discharge) by 20 million m^3 or 40 per cent in 2026 over the 2015 baseline. Water consumption in 2015 was 45 million m^3. This target is in line with the UN 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.

Typically, TransAlta withdraws in the range of 220-240 million m^3 of water across our fleet. In 2022, we withdrew approximately 230 million m^3 (2021 – 240 million m^3) and returned approximately 210 million m^3 (2021 – 210 million m^3) or 89 per cent. Overall, water consumption was approximately 30 million m^3 (2021 – 30 million m^3).

The following represents our total water consumption (million m^3) over the last three years. Some values do not sum to the indicated total due to rounding. Figures below have been rounded to the nearest 10 million m^3:

Year ended Dec. 31	2022	2021	2020
Water withdrawal	**230**	240	230
Water discharge	**210**	210	200
Total water consumption (million m^3)	**30**	30	40

Water Security

Our largest water withdrawal and discharge occurs at our Sarnia gas cogeneration facility (which produces both electricity and steam for our customers). 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 97 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. 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 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.

Dam Safety

Our dam safety programs include all hydroelectric developments, constructed ponds and fluid retaining structures such as ash lagoons and canals, as well as associated equipment and structures and the personnel required to operate, maintain and inspect these items. They are governed through our Dam Safety Policy and Dam Safety Management System, which includes requirements on design, modification and decommissioning, operation, maintenance and surveillance, public safety, emergency management and risk management.

TransAlta's Board and its President and CEO oversee the effectiveness of our dam safety programs and receive regular updates. In 2022, a member of the Board was designated as the Company's Dam Safety Advisor to assist the Board in fulfilling its oversight role in regard to the Company's dam safety practices given the unique and technical aspects of dam safety. In addition, TransAlta engages an external Dam Safety Review Panel to provide external review of the program and its management, including overall assessment and benchmarking against other national and international programs.

Our monitoring programs include:

- Regular operations and engineering inspections;
- Testing of critical equipment;
- Numerous instruments in the dams monitoring water level, temperature, movement, earthquake detection;
- Use of drones and satellite remote movement monitoring;
- Emergency plans and exercises with internal and external stakeholders; and
- Regular third-party reviews that are shared with the regulators.

We work closely with local stakeholders including conservation authorities and public agencies on watershed management, emergency planning and flood response. For example, in southern Alberta, our hydroelectric facilities have played an increasingly important water management role following the flood of 2013. In 2021, we renewed our previous agreement with the Government of Alberta for another five years 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 River System (which includes the Interlakes, Pocaterra and Barrier hydroelectric plants) for drought mitigation efforts. In 2022, we started decommissioning the Keephills Ash Lagoon, a facility that is no longer needed for ash storage following the coal-to-gas conversion of Keephills Unit 2. This three-year project will reshape the existing lagoon so that it is stable for the long term and is the first step towards delicensing the structure.

TransAlta is proud of its reputation in dam safety. We participate in the Canadian Dam Association, Dam Safety Interest Group of the Centre for Energy Advancement through Technological Innovation, United States Society on Dams, Canadian Geotechnical Society, and Association of State Dam Safety Officials.

For information on our corporate emergency management program, refer to Public Health and Safety in the Engaging with Our Stakeholders to Create Positive Relationships section of this MD&A.

Waste

The importance of environmental protection and waste management is outlined in our Environmental Policy as a corporate responsibility for TransAlta and its employees, and contractors working on TransAlta's behalf. Our waste data is reported annually to a number of different regulatory bodies.

Our waste reduction target is that by 2022 TransAlta will reduce total waste generation by 80 per cent over the 2019 baseline of 1.5 million tonnes equivalent of waste generation. In 2022, we achieved this target with a 86 per cent waste reduction over 2019 levels.

In 2022, our operations generated approximately 208,000 tonnes equivalent of waste (2021 – 515,000 tonnes). Of the total waste generated, 89 per cent was non-hazardous waste and one (1) per cent was directed to landfill (2021 – 0.2 per cent).

The following represents our total waste production over the last three years. Figures have been rounded to the nearest one thousand:

Year ended Dec. 31	2022	2021	2020
Total waste generation (tonnes equivalent)	**208,000**	515,000	1,135,000
Waste to landfill (tonne eq.)	**2,000**	1,000	11,000
Waste recycled (tonne eq.)	**27,000**	31,000	31,000
Waste reuse (tonne eq.)	**151,000**	176,000	533,000
% of total waste to landfill	**1**	0.2	1
% of total waste: hazardous	**11**	5	2
% hazardous waste to landfill	**0.6**	1.0	0.4

Our reuse waste or byproduct waste is generally sold to third parties. 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.

Coal Ash Management

Given our transition off coal, we ceased producing fly ash waste in Canada at the end of 2021 and will no longer produce it past the end of 2025 in the US. The Company 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.

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 ceased operations on Dec. 31, 2021, as part of our target to discontinue coal-fired power generation in Canada at the end of 2021. The mine reclamation has been progressively executed as part of our regulatory approvals and our target is to have it fully reclaimed by 2046. In 2022, our reclamation team submitted our final reclamation plans. The updated plans align with community priorities for the reclaimed land. 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. 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.

Environmental Incidents and Spills

Minimizing our impact on the environment supports healthy ecosystems and mitigates our environmental compliance risk and reputational risk. We maintain corporate incident management procedures, as part of our Total Safety Management System, for appropriate initial response, investigation and lessons learned to minimize environmental incidents. 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 2022, we recorded one (1) regulatory non-compliance environmental incident (2021 – two incidents). The incident occurred at our Sarnia cogeneration facility and was a wastewater discharge exceedance from our neutralization sump during water treatment. The incident resulted in two environmental enforcement actions totalling $35,000.

Regulatory non-compliance environmental incidents follow:

Year ended Dec. 31	2022	2021	2020
Regulatory non-compliance environmental incidents	**1**	2	2

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 immediate response to all environmental spills to ensure assessment, containment and recovery of spilled materials result in minimal impact to the environment.

The estimated volume of spills in 2022 was 246 m^3 (2021 – 6 m^3). Spill volumes in 2022 were higher due to one environmental incident recorded at our Sarnia facility. The incident involved the release of low pH wastewater discharge during water treatment and had negligible environmental impacts.

Significant environmental incidents follow:

Year ended Dec. 31	2022	2021	2020
Significant environmental incidents	**0**	0	6

There is a potential that ash ponds associated with our remaining 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.

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 seasonal weather variations. Variations in winter weather affect the demand for electrical heating requirements while 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 facilities. 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, strong winds, wildfires, earthquakes, tornados and cyclones), 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. In certain cases, there is the potential that some events may not excuse us from performing our obligations pursuant to agreements with third parties. The fact that several of our generation facilities are located in remote areas may make access for repair of damage difficult. Refer to the Governance and Risk Management section of this MD&A for further discussion on weather-related risks.

Delivering Reliable, Low-Cost and Sustainable Energy

TransAlta's goal is to be a leading customer-centred clean electricity company, one that is committed to a sustainable future. Our strategy is focused on meeting our customers' need for clean, low-cost and reliable electricity, operational excellence and continual improvement in everything that we do. This section covers manufactured, intellectual and social and relationship capital management as per guidance from the International Integrated Reporting Framework.

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 renewable energy facilities, battery energy storage systems and hybrid solutions, or long-term offtake agreements from its existing and future renewable and gas-fired 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 customers if their sites are operating 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.

Grid Resiliency

As a large electricity generator, TransAlta works diligently to ensure the power we provide our customers is reliable, affordable and has low environmental impact. We provide decentralized and customized power solutions to industrial customers. In 2021, TransAlta agreed to build the Northern Goldfields solar project in Western Australia to provide renewable solar electricity supported with a battery energy storage system to the Goldfields-based operations of BHP. We also supply power to centralized power systems and own and operate transmission grid infrastructure in Alberta that addresses system reliability needs.

In all jurisdictions where we operate, we work closely with the system operators to ensure overall supply adequacy and reliability of the grid. 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. We are also committed to ensuring strong compliance with North American Electric Reliability Corporation standards and Alberta Reliability Standards for the power plant and transmission infrastructure that we own and operate.

As a Company, we are keenly focused on deploying clean power generation and new technology solutions to meet the emerging and future needs of the electric system that we operate in. For example, in Alberta, we brought online the first battery storage project, called WindCharger, in 2020 that is co-located with our Summerview II wind facility to create an emissions-free, peaking resource. This resource is participating in the AESO’s pilot fast frequency response initiative to support intertie operations. Beyond the fast frequency response initiative, WindCharger introduces a resource with a response time that is unmatched by existing generation technologies and can be operated with a high level of reliability to support the growing need for primary frequency response and system inertial response and resiliency to support a decarbonized grid with a supply mix made up of intermittent renewable resources.

For more information on technologies to support grid resiliency, refer to the Enabling Innovation and Technology Adoption section of this MD&A. For more information on extreme weather events and natural disasters, refer to Weather in the Progressive Environmental Stewardship section of this MD&A.

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 GSSC of the Board. The GSSC assists the Board in fulfilling its oversight responsibilities with respect to the Company's monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environment, health and safety and social well-being, including human rights, working conditions and responsible sourcing.

The following policies help govern sustainability at TransAlta and are publicly available in the Governance section of the Investor Centre on our website:

- Corporate Code of Conduct
- Supplier Code of Conduct
- Whistleblower Policy
- Total Safety Management Policy
- Human Rights and Discrimination Policy
- Indigenous Relations Policy
- Board and Workforce Diversity Policy and Diversity and Inclusion Pledge
- Environmental Policy

Our sustainability memberships include key sustainability organizations and working groups such as the EXCEL Partnership, the Canadian Business for Social Responsibility and the Electricity Canada Sustainable Electricity Steering Committee, which all provide validation and support of our sustainability strategy and practices.

In 2022, we refreshed our material sustainability factors. They are presented below in alphabetical order.

- Air quality and emissions
- Asset integrity and grid resiliency
- Biodiversity and land management
- Climate change and greenhouse gas emissions
- Dam safety
- Energy use and conservation
- Equity, diversity and inclusion
- Ethics and business conduct
- Health, safety and well-being
- Human rights and labour practices
- Indigenous relationships and partnerships
- Information asset protection and cybersecurity
- Renewable energy and innovative technologies
- Security and emergency preparedness and response
- Stakeholder engagement and community investment
- Supply chain and sustainable sourcing
- Sustainability governance
- Sustainable finance
- Talent attraction, retention and development
- Waste management
- Water management

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

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 interact.

During the year ended Dec. 31, 2022, the global economy continued to recover from the COVID-19 pandemic. On Feb. 24, 2022, the Russian Government’s invasion of Ukraine set off historic policy actions and global coordination of sanctions and commitments to reduce dependency on Russian energy including natural gas. This has contributed to global supply chain disruptions, commodity price volatility and potential increases to cybersecurity risk. The Company continues to mitigate inflationary and supply chain risks pertaining to current development projects by locking in the prices of key materials where possible and employing other supply chain risk mitigation strategies. A prolonged conflict and recent inflationary and supply chain dynamics may impact future construction project costs with the risk of rising prices on key materials. Accordingly, as the Russia-Ukraine conflict continues to evolve and its indirect impacts along with rising inflation rates within the global markets remain uncertain at this time, management continues to monitor and assess the impacts.

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 — Disclosure 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 the 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 Company; and
- Energy Trading Code of Conduct, which applies to all of our employees engaged in energy marketing.

Our Corporate Code of Conduct outlines 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 Company and ensures that the Company 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 Company’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 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 ERM reporting.

The GSSC is responsible for developing and recommending to the Board a set of corporate governance principles applicable to the Company 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 Company’s monitoring of climate change, environmental, health and safety regulations, public policy changes and the development of strategies, policies and practices for climate change, environmental, health and safety and social well-being, including human rights, working conditions and responsible sourcing. The GSSC also receives an annual report on the annual codes of conduct certification process. For further information on the Board's oversight of climate-related factors, refer to the Climate Change Governance in ESG section of this MD&A.

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

The HRC is empowered by the Board to review and approve key compensation and human resources policies of the Company that are intended to attract, recruit, retain and motivate employees of the Company. 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 Company's strategic plans. The IPC provides assistance to the Board in fulfilling its oversight responsibilities with respect to broadly reviewing and monitoring project management and control processes, financial profile, capital costs, procurement practices and project schedules in a more in-depth manner than time permits during regularly scheduled Board meetings.

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 and Chief Financial Officer.

The Investment Committee is a management committee chaired by our Senior Vice-President, M&A, Strategy and Treasurer and comprises the President and Chief Executive Officer; Executive Vice-President, Finance and Chief Financial Officer; Executive Vice President, Legal, Commercial and External Affairs; Executive Vice-President, Generation; Executive Vice-President, Alberta; and Vice-President, Strategic Finance and Investor Relations. 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 and Chief Financial Officer and comprises 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 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 Hydro Operating Committee has an initial term of six years, which can be extended for an additional two years.

TransAlta is listed on the Toronto Stock Exchange 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 and guidelines of the TSX and Canadian Securities Administrators: (i) Multilateral Instrument 52-109 — Certification of Disclosure in Issuers’ Annual and Interim Filings; (ii) National Instrument 52-110 — Audit Committees; (iii) National Policy 58-201 — Corporate Governance Guidelines; and iv) National Instrument 58-101 — Disclosure of Corporate Governance Practices. As a “foreign private issuer” under US securities laws, we are generally permitted to comply with Canadian corporate governance requirements. Additional information regarding our governance practices can be found in our most recent management information circular.

Risk Controls

Our risk controls have several key components:

Enterprise Tone

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

Policies

We maintain a comprehensive set of enterprise-wide policies. These policies establish delegated authorities and limits for business transactions, as well as allow for an exception approval process. Periodic reviews and audits are performed to ensure compliance with these policies. All employees and directors are required to sign a Corporate 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 Corporate 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 scenario analysis 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, 2022, associated with our proprietary commodity risk management activities was $4 million (2021 – $2 million). Refer to the Risk Factors – Commodity Price Risk section of this MD&A below for further discussion.

Risk Factors

Risk is an inherent factor of doing business. The following section addresses some, but not all, risk factors that could affect our future plans, performance, results or outcomes and our activities in mitigating those risks. These risks do not occur in isolation, but must be considered in conjunction with each other. Further information on the Company's risk factors can be found in the Risk Factors section of the AIF, which risk factors are hereby incorporated by reference and 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 Company means such an effect on the Company 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 (loss) of changes in certain key variables. The analysis is based on business conditions and production volumes in 2022. 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 (Per cent)	Approximate impact on net earnings (million)
Availability/production	1	$14

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 Company. 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 production 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;
- Monitoring the condition of our assets and performing predictive analytics, and adjusting our maintenance programs to maintain availability;
- 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 2022, we had approximately 83 per cent (2021 – 78 per cent) of total 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 2022, 82 per cent (2021 – 70 per cent) of our gas consumption used in generating electricity was contractually fixed or passed through to our customers and 100 per cent (2021 – 80 per cent) of our purchased coal was contractually fixed.

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

Natural Gas Supply and Price Risk

Having sufficient natural gas and natural gas transportation services available at our gas facilities is essential to maintaining the reliability and availability of those facilities. Ensuring adequate pipeline transportation service and natural gas supply for our gas 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 caused 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; and
- Monitoring pipeline maintenance schedules and transportation availability.

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, Australia 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 abatement 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;
- Conducting environmental health and safety management system audits to assess conformance to our Total Safety Management System, which is designed to continuously improve performance;
- Committing significant experienced resources to work with regulators in Canada, Australia 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 GHG, mercury, SO_2 and NO_x, which will be adjusted as regulations are finalized;
- Purchasing carbon emissions reduction offsets or credits;
- Investing in renewable energy projects, such as wind, solar and hydro generation and storage technologies; 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 (loss) 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.

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, 2021. We had no material counterparty losses in 2022. 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, 2022:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables[1,2]	87	13	100	**1,585**
Long-term finance lease receivables	100	—	100	**129**
Risk management assets[1]	92	8	100	**870**
Loan receivable[2]	—	100	100	**37**
Total				**2,621**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $37 million loan receivable included within other assets with a counterparty that has no external credit rating. The current portion of $4 million was excluded from trade and other receivables as it is included in loan receivable in the table above.

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 $64 million (2021 – $37 million).

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.

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, cash flows or the value of our foreign investments to the extent that these positions or cash flows are not hedged or the hedges are ineffective.

We manage our currency rate risk by establishing and adhering to policies that 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 senior 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 and Australian exposure, net of debt service and sustaining capital expenditures, is managed with forward foreign exchange contracts.

The sensitivity of our net earnings to changes in foreign exchange rates has been prepared using management’s assessment that an average $0.03 increase or decrease in the US or Australian currencies relative to the Canadian dollar is a reasonable potential change over the next quarter and is shown below:

Factor	Increase or decrease	Approximate impact on net earnings (million)
Exchange rate	$0.03	$14

Liquidity Risk

Liquidity risk relates to our ability to access capital to be used to fund capital projects, refinance debt and pay liabilities, engage in trading and hedging activities 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, or establishing normal course derivative or hedging transactions, including those undertaken by our Energy Marketing segment.

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, 2022, we had liquidity of $2.1 billion comprising amounts not drawn under our committed credit facilities and cash on hand net of bank overdraft.

We manage liquidity risk by:

- Preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital;
- Reporting liquidity risk exposure and risk management activities on a regular basis to the Commodity Risk & Compliance Committee, senior management and the AFRC;
- Maintaining a strong balance sheet;
- Maintaining sufficient undrawn committed credit lines to support potential liquidity requirements; and
- Monitoring trading positions.

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;
- Monitoring the mixture of floating and fixed rate debt and adjusting to ensure efficiency; and
- Opportunistically hedging probable debt issuances and outstanding variable rate borrowings using interest rate swaps.

At Dec. 31, 2022, approximately nine per cent (2021 – three per cent) of our total long-term debt 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 (Per cent)	Approximate impact on net earnings (million)
Interest rate	50 bps	$1

London Interbank Offered Rate reform could impact interest rate risk with respect to the Company's Canadian dollar credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The facilities reference the Canadian Dollar Offer Rate ("CDOR") for Canadian-dollar drawings. In addition, the non-recourse bond references the three-month CDOR. Cessation of the three-month CDOR will occur on June 28, 2024, which will impact the facilities and the non-recourse bond.

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 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:

- 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 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;
- Monitoring the financial viability of Centralia suppliers; and
- Hedging diesel exposure in mining and transportation costs.

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:

- Possessing a labour relations strategy;
- Applying a human-centric approach that emphasizes the employee experience, including actively improving our workplace culture, focusing on ED&I strategies and offering health and wellness programming and initiatives;
- Focusing on employee learning and development;
- 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 employees have the appropriate training and qualifications to perform their jobs.

In 2022, approximately 31 per cent (2021 – 33 per cent) of our labour force was covered by 11 collective bargaining agreements (2021 – 11). In 2022, we successfully renegotiated six (2021 – one) collective bargaining agreements. Of these six agreements, three agreements are for a five-year duration, one agreement is for a four-year duration, one agreement is for a three-year duration and one agreement is a one-year duration. We expect to renegotiate three collective bargaining agreements in 2023. Any problems in negotiating these collective bargaining agreements could lead to higher employee costs and a work stoppage or strike, which could have a material adverse effect on us.

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. Over the past few years, geopolitical tensions and the pandemic have significantly impacted the cybersecurity ecosystem, increasing the frequency and diversity of cyberattacks, including threats of war driven cyberattacks (i.e., terrorism) against critical infrastructure and threat actors taking advantage of the pandemic (e.g., charity scams) and hybrid working environments. We anticipate the cyber threat landscape to continue evolving, increasing threats of ransomware, compromised insider threats, supply chain attacks, advanced targeted phishing and artificial intelligence.

Cyber threats originate from various sources and vectors, from nation states, organized hacking groups or malware/ransomware. The cyber threat landscape continues to evolve, as we see cyber threats shift their focus from traditional attacks against perimeter information technology systems, to more effective attacks, such as phishing and ransomware.

TransAlta has established a comprehensive cybersecurity program, forming the foundation to implement effective security practices, comprising of structured and tailored plans to manage cybersecurity risks. As information technology /operation technology systems are integral to TransAlta’s business operations, the risk of a cybersecurity incident threatens the safety of the public, TransAlta personnel and/or business functions, service delivery, reputation and profitability.

TransAlta maintains compliance to regulatory, legislative, and business requirements (e.g. NERC CIP, SOX, Privacy) by adopting industry endorsed standards and frameworks (e.g., National Institute of Standards and Technology (“NIST”), CIP/Reliability Standards) to implement a pragmatic fit-for-purpose cybersecurity program, implementing cybersecurity controls and processes under the following domains:

- Identify: TransAlta conducts comprehensive risk assessments to identify and document the organization's assets, systems and data, as well as potential risks and vulnerabilities.
- Protect: TransAlta implements security controls, policies and procedures to safeguard the organization's assets, systems and data from unauthorized access, use, disclosure, disruption, modification or destruction. This includes implementing access controls, encryption, firewalls and intrusion detection/prevention systems to protect the organization's networks and systems.
- Detect: TransAlta implements incident detection and response capabilities to detect and respond to cyber incidents. This includes monitoring systems, networks and data for suspicious activity.
- Respond: TransAlta has developed incident response plans, procedures and teams, as well as provided training and conducted exercises to ensure that these plans and procedures are operating effectively.
- Recover: TransAlta has developed disaster recovery and business continuity plans, and it conducts test exercises of these plans to ensure their effectiveness. This includes identifying critical systems, data and process to ensure the continuity of business operations, as well as implementing backup and recovery solutions to ensure that the organization's data can be restored in the event of a disaster.

Although complete cyber risk elimination is not achievable given the evolving cyber threat landscape, the security controls implemented to detect, prevent and respond to a cyber incident significantly reduce TransAlta’s cyber risk and potential incident impact to acceptable levels. In addition, cyber insurance is utilized to further manage and transfer residual cyber risk to TransAlta’s business. We continue to improve our overall security maturity and defense capabilities against cyber threats and align cybersecurity practices to industry standards, business objectives and regulatory compliance requirements.

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.

Growth Risk

Our business plan includes growth by making suitable acquisitions or contracting new build opportunities. There can be no assurance that we will be able to identify attractive growth opportunities in the future, that we will be able to complete growth opportunities that increase the amount of cash available for distribution, or that growth opportunities will be successfully integrated into our existing operations. The successful execution of the growth strategy requires careful timing and business judgment, as well as the resources to complete the due diligence and evaluation of such opportunities and to acquire and successfully integrate those assets into our business.

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 constantly evolving. Our tax filings are subject to audit by taxation authorities. Management believes that it has adequately provided for income taxes as required by the Income Tax Act and IFRS, based on all information currently available.

The Company 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 Company.

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

Factor	Increase or decrease (Per cent)	Approximate impact on net earnings (million)
Tax rate	1	$4

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 the remedy claimed and the availability of insurance coverage. There can be no assurance that any particular dispute, claim or proceeding will be resolved in our favour or our liabilities with respect to such claims will not have a material adverse effect on us or our business, operations or financial results. Refer to the Other Consolidated Analysis section of this MD&A for further details.

Other Contingencies

We maintain a level of insurance coverage deemed appropriate by management. During renewal of the insurance policies on Dec. 31, 2021, a coverage restriction was added for losses resulting from a foundation failure at the Kent Hills 1 and 2 wind facilities only. There were no other significant changes to our insurance coverage during renewal of the insurance policies on Dec. 31, 2022. 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.

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, 2022, the majority of our workforce supporting and executing our ICFR and DC&P returned to work and continue to work remotely on a hybrid basis. The Company has implemented appropriate controls and oversight for both in-office and remote work. There has been minimal impact to the design and performance of our internal controls.

ICFR is a framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the 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 Company'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, 2022, 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 ("TransAlta") has a code of conduct that applies to all employees and is signed annually. The Corporate Code of Conduct can be viewed on TransAlta's website (www.transalta.com). Management believes the system of internal controls, review procedures and established policies provides reasonable assurance as to the reliability and relevance of financial reports. Management also believes that TransAlta's operations are conducted in conformity with the law and with a high standard of business conduct.

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

John Kousinioris
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and Chief Financial Officer

February 22, 2023

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 controls over financial reporting are processes that involve human diligence and compliance and are 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 equity accounts for our investment in SP Skookumchuck Investment, 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 2022 Consolidated Financial Statements of TransAlta for joint operations and equity accounted investments are 4 per cent and 17 per cent of the Company's total and net assets, respectively, as of Dec. 31, 2022, and 9 per cent of the Company's revenues.

Changes in Internal Controls over Financial Reporting

There has been no change in the Company's internal control over financial reporting that occurred during the year covered by this Annual Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2022 and has concluded that such internal control over financial reporting are effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2022, 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.

John Kousinioris	**Todd Stack**
President and Chief Executive Officer	Executive Vice President, Finance and Chief Financial Officer

February 22, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of 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, 2022, 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 (the "Company") maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, 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 of the Sheerness Generating Station and equity accounted joint venture of SP Skookumchuck Investment, LLC which are included in the 2022 consolidated financial statements of the Company and constituted 4% and 17% of total and net assets, respectively, as of December 31, 2022, and 9% of revenues for the year then ended. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of the joint operations of the Sheerness Generating Station and equity accounted joint venture of SP Skookumchuck Investment, 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, 2022 and 2021, and the related consolidated statements of earnings (loss), comprehensive loss, changes in equity and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and our report dated February 22, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the 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 company; (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 company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated 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.

/s/Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada

February 22, 2023

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Company") as of December 31, 2022 and 2021, the related consolidated statements of earnings (loss), comprehensive loss, changes in equity and cash flows, for each of the three years in the period ended December 31, 2022, 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 the Company at December 31, 2022 and 2021, and the financial performance and its cash flows for each of the three years in the period ended December 31, 2022, 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"), the Company's internal control over financial reporting as of December 31, 2022, 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 February 22, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company'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 the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our 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.

Valuation of Long-Lived Assets related to certain cash generating units ("CGU"s) within the Wind & Solar segment and the Hydro segment and Goodwill related to the Wind & Solar segment

Description of the Matter	As disclosed in notes 2(G), 2(H), 2(P)(I), 7 and 22 of the consolidated financial statements, the Company owns significant Wind & Solar and Hydro generation assets and has recognized goodwill from historical acquisitions which must be tested for impairment at least annually or when indicators are present. The carrying value of Goodwill related to the Wind & Solar segment was $176 million and the carrying value of long-lived assets in the Wind & Solar segment and the Hydro segment that had indicators of impairment was $748 million and $88 million respectively as at December 31, 2022. Determining the recoverable amounts for the Wind & Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind & Solar segment and Hydro segment with indicators of impairment ("Wind & Solar CGUs" and "Hydro CGUs") for the asset impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgment 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 electricity production, sales prices, cost inputs, and determining the appropriate discount rate.
How We Addressed the Matter in Our Audit	We obtained an understanding of management's process for estimating the recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs and Hydro CGUs. We evaluated the design and tested the operating effectiveness of controls over the Company's processes to determine the recoverable amount. Our audit procedures to test the Company's recoverable amount of the Wind & Solar segment and the Wind & Solar CGUs and Hydro CGUs with indicators of impairment included, among others, comparing the significant assumptions used to estimate cash flows to current contracts with external parties and historical trends and obtaining historical electricity generation data to evaluate future electricity production forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future sales prices by comparing them to externally available third-party future electricity 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(P)(IV), 14 and 26 of the consolidated financial statements, the Company 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, 2022 the fair value of the Company's derivative financial instruments classified as level III was $782 million net risk management liability. 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 prices, discount rates, volatility, credit value adjustments, liquidity and delivery volumes, 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 Company'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 value adjustments, and liquidity assumptions to third-party data as well as comparing terms such as delivery volumes and timing to executed commodity contracts. We compared the delivery volume assumptions to historical information. We performed a sensitivity analysis to evaluate assumptions including future commodity prices, delivery volumes and discount rates. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the fair value by evaluating the key assumptions and methodologies.

/s/Ernst & Young LLP

Chartered Professional Accountants

We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.

Calgary, Canada

February 22, 2023

Consolidated Statements of Earnings (Loss)

(in millions of Canadian dollars except where noted)

Year ended Dec. 31	2022	2021	2020
Revenues (Note 5)	**2,976**	2,721	2,101
Fuel and purchased power (Note 6)	**1,263**	1,054	805
Carbon compliance	**78**	178	163
Gross margin	**1,635**	1,489	1,133
Operations, maintenance and administration (Note 6)	**521**	511	472
Depreciation and amortization	**599**	529	654
Asset impairment charges (Note 7)	**9**	648	84
Taxes, other than income taxes	**33**	32	33
Net other operating (income) loss (Note 8)	**(58)**	8	(11)
Operating income (loss)	**531**	(239)	(99)
Equity income (Note 9)	**9**	9	1
Finance lease income	**19**	25	7
Net interest expense (Note 10)	**(262)**	(245)	(238)
Foreign exchange gain	**4**	16	17
Gain on sale of assets and other (Note 18)	**52**	54	9
Earnings (loss) before income taxes	**353**	(380)	(303)
Income tax expense (recovery) (Note 11)	**192**	45	(50)
Net earnings (loss)	**161**	(425)	(253)
Net earnings (loss) attributable to:			
TransAlta shareholders	**50**	(537)	(287)
Non-controlling interests (Note 12)	**111**	112	34
	161	(425)	(253)
Net earnings (loss) attributable to TransAlta shareholders	**50**	(537)	(287)
Preferred share dividends (Note 29)	**46**	39	49
Net earnings (loss) attributable to common shareholders	**4**	(576)	(336)
Weighted average number of common shares outstanding in the year (millions)	**271**	271	275
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 28)	**0.01**	(2.13)	(1.22)

See accompanying notes.

Consolidated Statements of Comprehensive Loss

(in millions of Canadian dollars)

Year ended Dec. 31	2022	2021	2020
Net earnings (loss)	**161**	(425)	(253)
Other comprehensive loss			
Net actuarial gains (losses) on defined benefit plans, net of tax[1]	**37**	37	(11)
Fair value losses on third-party investments, net of tax (Note 9)	**(1)**	—	—
Losses on derivatives designated as cash flow hedges, net of tax	**—**	—	(1)
Total items that will not be reclassified subsequently to net earnings (loss)	**36**	37	(12)
Gains (losses) on translating net assets of foreign operations, net of tax	**21**	(14)	(11)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax[2]	**(25)**	—	11
Gains (losses) on derivatives designated as cash flow hedges, net of tax[3]	**(556)**	(200)	20
Reclassification of losses (gains) on derivatives designated as cash flow hedges to net earnings (loss), net of tax[4]	**100**	(8)	(110)
Total items that will be reclassified subsequently to net earnings (loss)	**(460)**	(222)	(90)
Other comprehensive loss	**(424)**	(185)	(102)
Total comprehensive loss	**(263)**	(610)	(355)
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(318)**	(693)	(439)
Non-controlling interests (Note 12)	**55**	83	84
	(263)	(610)	(355)

(1) Net of income tax expense of $12 million for the year ended Dec. 31, 2022 (2021 – $11 million expense, 2020 – $3 million recovery).
(2) Net of income tax recovery of $3 million for the year ended Dec. 31, 2022 (2021 and 2020 – nil).
(3) Net of income tax recovery of $138 million for the year ended Dec. 31, 2022 (2021 – $55 million recovery, 2020 – $8 million expense).
(4) Net of reclassification of income tax expense of $26 million for the year ended Dec. 31, 2022 (2021 – $2 million recovery, 2020 – $31 million recovery).

See accompanying notes.

Consolidated Statements of Financial Position

(in millions of Canadian dollars)

As at Dec. 31	2022	2021
Current assets		
Cash and cash equivalents	**1,134**	947
Restricted cash (Note 25)	**70**	70
Trade and other receivables (Note 13)	**1,589**	651
Prepaid expenses	**33**	29
Risk management assets (Note 14 and 15)	**709**	308
Inventory (Note 16)	**157**	167
Assets held for sale (Note 18)	**22**	25
	3,714	2,197
Non-current assets		
Investments (Note 9)	**129**	105
Long-term portion of finance lease receivables (Note 17)	**129**	185
Risk management assets (Note 14 and 15)	**161**	399
Property, plant and equipment (Note 19)		
Cost	**14,012**	13,389
Accumulated depreciation	**(8,456)**	(8,069)
	5,556	5,320
Right-of-use assets (Note 20)	**126**	95
Intangible assets (Note 21)	**252**	256
Goodwill (Note 22)	**464**	463
Deferred income tax assets (Note 11)	**50**	64
Other assets (Note 23)	**160**	142
Total assets	**10,741**	9,226
Current liabilities		
Bank overdraft (Note 14)	**16**	—
Accounts payable and accrued liabilities (Note 13)	**1,346**	689
Current portion of decommissioning and other provisions (Note 24)	**70**	48
Risk management liabilities (Note 14 and 15)	**1,129**	261
Current portion of contract liabilities	**8**	19
Income taxes payable	**73**	8
Dividends payable (Note 28 and 29)	**68**	62
Current portion of long-term debt and lease liabilities (Note 25)	**178**	844
	2,888	1,931
Non-current liabilities		
Credit facilities, long-term debt and lease liabilities (Note 25)	**3,475**	2,423
Exchangeable securities (Note 26)	**739**	735
Decommissioning and other provisions (Note 24)	**659**	779
Deferred income tax liabilities (Note 11)	**352**	354
Risk management liabilities (Note 14 and 15)	**333**	145
Contract liabilities	**12**	13
Defined benefit obligation and other long-term liabilities (Note 27)	**294**	253
Equity		
Common shares (Note 28)	**2,863**	2,901
Preferred shares (Note 29)	**942**	942
Contributed surplus	**41**	46
Deficit	**(2,514)**	(2,453)
Accumulated other comprehensive income (loss) (Note 30)	**(222)**	146
Equity attributable to shareholders	**1,110**	1,582
Non-controlling interests (Note 12)	**879**	1,011
Total equity	**1,989**	2,593
Total liabilities and equity	**10,741**	9,226

Commitments and contingencies (Note 37)
See accompanying notes.

On behalf of the Board:

John P. Dielwart
Director

Bryan Pinney
Chair of Audit, Finance and Risk Committee

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net earnings (loss)	—	—	—	(537)	—	(537)	112	(425)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(14)	(14)	—	(14)
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(208)	(208)	—	(208)
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	37	37	—	37
Intercompany FVTOCI investments	—	—	—	—	29	29	(29)	—
Total comprehensive income (loss)				(537)	(156)	(693)	83	(610)
Common share dividends (Note 28)	—	—	—	(51)	—	(51)	—	(51)
Preferred share dividends (Note 29)	—	—	—	(39)	—	(39)	—	(39)
Effect of share-based payment plans (Note 31)	5	—	8	—	—	13	—	13
Distributions paid and payable, to non-controlling interests	—	—	—	—	—	—	(156)	(156)
Balance, Dec. 31, 2021	2,901	942	46	(2,453)	146	1,582	1,011	2,593
Net earnings	**—**	**—**	**—**	**50**	**—**	**50**	**111**	**161**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(4)**	**(4)**	**—**	**(4)**
Net losses on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(456)**	**(456)**	**—**	**(456)**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**37**	**37**	**—**	**37**
Intercompany and third-party FVTOCI investments	**—**	**—**	**—**	**—**	**55**	**55**	**(56)**	**(1)**
Total comprehensive income (loss)				**50**	**(368)**	**(318)**	**55**	**(263)**
Common share dividends (Note 28)	**—**	**—**	**—**	**(57)**	**—**	**(57)**	**—**	**(57)**
Preferred share dividends (Note 29)	**—**	**—**	**—**	**(46)**	**—**	**(46)**	**—**	**(46)**
Shares purchased under NCIB (Note 28)	**(46)**	**—**	**—**	**(8)**	**—**	**(54)**	**—**	**(54)**
Effect of share-based payment plans (Note 31)	**8**	**—**	**(5)**	**—**	**—**	**3**	**—**	**3**
Distributions paid and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(187)**	**(187)**
Balance, Dec. 31, 2022	**2,863**	**942**	**41**	**(2,514)**	**(222)**	**1,110**	**879**	**1,989**

(1) Refer to Note 30 for details on components of and changes in, accumulated other comprehensive income (loss).

See accompanying notes.

Consolidated Statements of Cash Flows

(in millions of Canadian dollars)

Year ended Dec. 31	2022	2021	2020
Operating activities			
Net earnings (loss)	**161**	(425)	(253)
Depreciation and amortization (Note 38)	**599**	719	798
Net gain on sale of assets	**(32)**	(54)	(9)
Accretion of provisions (Note 10 and 24)	**49**	32	30
Decommissioning and restoration costs settled (Note 24)	**(35)**	(18)	(18)
Deferred income tax expense (recovery) (Note 11)	**127**	(11)	(85)
Unrealized (gain) loss from risk management activities	**385**	(34)	42
Unrealized foreign exchange (gain) loss	**(82)**	(24)	1
Provisions and contract liabilities	**19**	(41)	9
Asset impairment charges (Note 7)	**9**	648	84
Equity income, net of distributions from investments (Note 9)	**(4)**	(5)	(1)
Other non-cash items	**(3)**	40	15
Cash flow from operations before changes in working capital	**1,193**	827	613
Change in non-cash operating working capital balances (Note 34)	**(316)**	174	89
Cash flow from operating activities	**877**	1,001	702
Investing activities			
Additions to property, plant and equipment (Note 19 and 38)	**(918)**	(480)	(486)
Additions to intangible assets (Note 21 and 38)	**(31)**	(9)	(14)
Restricted cash (Note 25)	**—**	(1)	(39)
Repayments (advances) in loan receivable (Note 23)	**18**	(3)	(5)
Acquisitions, net of cash acquired (Note 4 and 27)	**(10)**	(120)	(32)
Investments (Note 9)	**(10)**	—	(102)
Proceeds on sale of Pioneer Pipeline (Note 18)	**—**	128	—
Proceeds on sale of property, plant and equipment	**66**	39	6
Realized gain (loss) on financial instruments	**27**	(6)	2
Decrease in finance lease receivable	**46**	41	17
Other	**45**	(16)	(12)
Change in non-cash investing working capital balances	**26**	(45)	(22)
Cash flow used in investing activities	**(741)**	(472)	(687)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 25 and 34)	**449**	(114)	(106)
Repayment of long-term debt (Note 25 and 34)	**(621)**	(92)	(489)
Issuance of long-term debt (Note 25 and 34)	**532**	173	753
Issuance of exchangeable securities (Note 26)	**—**	—	400
Dividends paid on common shares (Note 28)	**(54)**	(48)	(47)
Dividends paid on preferred shares (Note 29)	**(43)**	(39)	(39)
Repurchase of common shares under NCIB (Note 28)	**(52)**	(4)	(57)
Proceeds on issuance of common shares	**3**	8	—
Realized gains on financial instruments	**42**	3	3
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(187)**	(156)	(97)
Decrease in lease liabilities (Note 25 and 34)	**(9)**	(8)	(25)
Financing fees and other	**(13)**	(4)	(11)
Change in non-cash financing working capital balances	**(2)**	(1)	(13)
Cash flow from (used in) financing activities	**45**	(282)	272
Cash flow from operating, investing and financing activities	**181**	247	287
Effect of translation on foreign currency cash	**6**	(3)	5
Increase in cash and cash equivalents	**187**	244	292
Cash and cash equivalents, beginning of year	**947**	703	411
Cash and cash equivalents, end of year	**1,134**	947	703
Cash taxes paid	**67**	57	36
Cash interest paid	**229**	220	201

See accompanying notes.

Notes to the 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 "Company") was incorporated under the Canada Business Corporations Act in March 1985. The Company became a public company in December 1992. The Company's head office is located in Calgary, Alberta.

Operating Segments

Generation Segments

The four generation segments of the Company are as follows: Hydro, Wind and Solar, Gas, and Energy Transition. The Company directly or indirectly owns and operates hydro, wind and solar, natural-gas-fired facilities, a coal-fired facility 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 ("Skookumchuck"). Segment revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Energy Marketing Segment

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

The Energy Marketing segment also performs services on behalf of certain assets outside of Alberta for the power marketing of available generating capacity as well as the procurement of the fuel and transmission needs of those assets by utilizing contracts of various durations for the forward sales of electricity and for the purchase of natural gas and transmission capacity. The results of these power marketing activities are included in the gross margin of each generation segment. The Energy Marketing segment allocates charges to recognize the performance of these activities to the applicable generation segment thereto.

Corporate Segment

The Corporate segment includes the Company's central finance, legal, administrative, corporate development, and investor relations functions. Activities and charges directly or reasonably attributable to other segments are allocated thereto. The Corporate segment includes our investment in EMG International, LLC ("EMG"), a wastewater treatment processing company, which is accounted for using the equity method. Revenues are derived from the design and construction of wastewater treatment facilities.

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, 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 Feb. 22, 2023.

C. Basis of Consolidation

The consolidated financial statements include the accounts of the Company and the subsidiaries that it controls. Control exists when the Company 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. Material Accounting Policies

The Company has reviewed its material accounting policies. The definition of material that management has used to judgmentally determine disclosure is that information is material if omitting it or misstating it could influence decisions users make on the basis of financial information.

A. Revenue Recognition

I. Revenue from Contracts with Customers

The majority of the Company’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 Company 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. Contract modifications are accounted for as separate contracts when the consideration for the additional promised goods reflects a stand-alone selling price. Otherwise, contract modifications are accounted for as part of the existing contract. If the additional goods are not considered distinct the transaction price can be affected and adjustments to previously recognized revenue can occur. If the additional goods are distinct, the existing and modified contracts are treated together as a new contract, with impacts reflected prospectively from the modification date. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the goods or services are 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 Company’s performance to date. The Company 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 Company’s contracts may contain more than one performance obligation.

Transaction Price

The Company 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 that has previously been constrained is assessed at each reporting period to determine whether the constraint is lifted. The consideration contained in some of the Company'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, the transaction price is allocated to each performance obligation in an amount that depicts the consideration the Company expects to be entitled to in exchange for transferring the good or service. The Company 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 Company'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 (e.g., monthly) in an amount representative of the 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 (e.g., 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 (e.g., 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 Company's 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 Company receives consideration before the performance obligations have been satisfied. A contract asset is recorded when the Company has rights to consideration for the completion of a performance obligation before it has invoiced the customer. The Company 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.

II. Revenue from Other Sources

Merchant Revenue

Revenues from non-contracted capacity (i.e., merchant) comprise energy payments, at market price, for each MWh produced and are recognized upon delivery.

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 Company 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. The Company also enters into contracts for differences and Virtual Power Purchase Agreements ("VPPA"). Contracts for differences are financial contracts whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. A VPPA is whereby the Company receives the difference between the fixed contract price per MWh and the settled market price. These arrangements are option-based derivatives and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

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 Company 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. 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 Company’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 Company 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 (loss) (“FVTOCI”).

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 FVTOCI 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 and investments in equity instruments. 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 Company 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 Company has made an accounting policy choice to recognize the impacts of the tax attributes in net interest expense.

The Company 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 Company 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 Company 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 Company 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 Company 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 Company'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 Company 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 Company 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 other comprehensive income (loss) ("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 accumulated other comprehensive income (loss) ("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 of 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.

C. Cash and Cash Equivalents

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

D. Inventory

I. Fuel
The Company's inventory balance is composed 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 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 and 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 Company 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 Company 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 Company 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.

E. Property, Plant and Equipment

The Company'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 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. Insurance 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. 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	2-50 years
Wind and Solar generation	2-30 years
Gas generation	2-35 years
Energy Transition	1-10 years
Capital spares and other	2-50 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction. 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.

F. 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 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. 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, software and intangibles under development. Estimated remaining useful lives of intangible assets are as follows:

Software	1-7 years
Power sale contracts	1-18 years

G. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

H. 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 Company's CGUs or groups of CGUs that are expected to benefit from the synergies of the business combination in which the goodwill arose. Accordingly, the Company performs its test for impairment, where the recoverable amount of the CGUs or groups of CGUs to which the goodwill relates is compared to its carrying amount for each operating segment. 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.

I. Income Taxes

The Company 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 Company 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.

Cash taxes paid disclosed on the Consolidated Statements of Cash Flows includes income taxes and taxes paid related to the Part VI.1 tax in Canada for the period.

J. Employee Future Benefits

The Company 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 prorated 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 Company's defined benefit pension plans give rise to recording an additional liability, letters of credit provided by the Company 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.

K. Provisions

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that the Company 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 Company 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 Company 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 Company determines the present value of the provision using the current discount rates that reflect the time value of money and associated risks. The Company 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(E)) 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 Company 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.

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.

L. Leases

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

I. Lessee

The Company 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 Company is the lessee and which are not exempt as short-term or low-value leases, the Company:

- 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 Company 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 Company'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 Company’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 Company is reasonably certain to exercise that option and periods covered by an option to terminate if the Company 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 Company expects to exercise the purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset.

The Company 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.

II. Lessor

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

Where the Company 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 Company determines that the contractual provisions of a contract contain, or are, a lease and result in the Company 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 Company 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.

M. Non-Controlling Interests

Non-controlling interests arise from business combinations in which the Company 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 Company determines on a transaction-by-transaction basis for which the measurement method is used. Non-controlling interests also arise from other contractual arrangements between the Company and other parties, whereby the other party has acquired an equity interest in a subsidiary and the Company 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 (loss) is attributed to the non-controlling interests even if this results in the non-controlling interests having a negative balance.

N. 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 Company'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 Company 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 Company 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 Company’s share of the joint venture’s net earnings or loss after the date of acquisition. The impact of transactions between the Company and joint ventures is eliminated based on the Company’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.

O. 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.

The optional fair value concentration test is 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 Company may elect to treat the acquisition as an asset acquisition and not as a business combination.

P. 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 Company'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 Company's financial position or performance. The key judgments and sources of estimation uncertainty are described below:

I. Impairment of PP&E and Goodwill

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

In estimating either fair value less costs of disposal or value in use using discounted cash flow methods, estimates and assumptions must be made about sales prices, cost of sales, production, fuel consumed, capital expenditures, retirement costs and other related cash inflows and outflows over the life of the facilities, which can range from three to 50 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 Company evaluates the market design, transmission constraints and the contractual profile of each facility, as well as the Company'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 Company evaluates synergies with regard 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 2020 to 2022 is disclosed in Notes 7, 19 and 22.

II. Leases

In determining whether the Company'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 Company 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 Company to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Company classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

III. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company 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 Company'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 Company'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 Company's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. Information regarding the impacts of the Company's tax policies is disclosed in Note 11.

IV. Financial Instruments and Derivatives

The Company’s financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 14. Some of the Company’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 Company’s estimates of pricing and production to allow the future transaction to be fulfilled.

When the Company enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Company 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 Company'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 Company 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. The Company also enters into PPAs and contracts for differences and judgment is applied to determine if the contract meets the "own use" exemption or if derivative treatment is required.

V. Project Development Costs

Project development 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 the Company, 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 or when there is uncertainty of timing of when the projects will proceed are charged to net earnings. 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 Company when determining the amount to be capitalized. Information regarding project development costs is disclosed in Note 23 and information on the write-off of project development costs is disclosed in Note 7.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K). Initial decommissioning provisions and subsequent changes thereto, are determined using the Company’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 to 2022 in respect of decommissioning and restoration provisions is disclosed in Notes 7, 19 and 24.

VII. Useful Life of PP&E

Each significant component of an item of PP&E is depreciated over its estimated useful life. Estimated useful lives are determined based on current facts and past experience and take into consideration the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecasted demand, the potential for technological obsolescence and regulations. The useful lives of PP&E are reviewed at least annually to ensure they continue to be appropriate. Information on changes in useful lives of facilities is disclosed in Note 19.

VIII. Employee Future Benefits

The Company 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. Disclosures on employee future benefits are disclosed in Note 32.

IX. Other Provisions

Where necessary, the Company 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 Company’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 8 and 24 with respect to other provisions.

X. Revenue from Contracts with Customers

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

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

When contracts are modified, management must exercise judgment to determine, depending upon the facts and circumstances of the changes to the contract, whether the modification is accounted for as a new contract or as part of the existing contract. If it is required to be accounted for as part of the existing contract the transaction price can be affected and adjustments to previously recognized revenue can occur, or the impacts can be reflected prospectively from the modification date.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount if that invoiced amount corresponds directly with the entity's performance to date.

XI. Classification of Joint Arrangements

Upon entering into a joint arrangement, the Company must classify it as either a joint operation or joint venture, and this classification affects the accounting for the joint arrangement. In making this classification, the Company 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.

XII. Significant Influence

Upon entering into an investment, the Company must classify it as either an investment in an associate or an investment under IFRS 9. In making this classification, the Company exercises judgment in evaluating whether the Company 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 Company 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, participation in policy-making processes, material transactions between the Company and investee, interchange of managerial personnel or providing essential technical information are considered when assessing if the Company has significant influence over an investee.

XIII. Change in Estimates

During the year ended Dec. 31, 2022, there were changes in estimates relating to asset useful lives and depreciation (Note 19), decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27). During the year ended Dec. 31, 2021, there were changes in estimates relating to decommissioning and other provisions (Note 24) and defined benefit obligation (Note 27).

3. Accounting Changes

A. Current Accounting Changes

Amendments to International Accounting Standards ("IAS") 37 Provisions, Contingent Liabilities and Contingent Assets

On May 14, 2020, the IASB issued Onerous Contracts – Cost of Fulfilling a Contract and amendments to IAS 37 Provisions, Contingent Liabilities and Contingent Assets to specify which costs to include when assessing whether a contract will be loss-making. The amendments are effective for annual periods beginning on or after Jan. 1, 2022, and the Company adopted these amendments as of Jan. 1, 2022. The amendments are effective for contracts for which an entity has not yet fulfilled all its obligations on or after the effective date. No adjustments resulted on adoption of the amendments on Jan. 1, 2022.

B. Future Accounting Changes

The Company closely monitors both new accounting standards and amendments to existing accounting standards issued by the IASB. The following standard has been issued but is not yet in effect.

Amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction

On May 7, 2021, the IASB issued amendments to IAS 12 Deferred Tax Related to Assets and Liabilities Arising from a Single Transaction. The amendments clarify that the initial recognition exemption under IAS 12 does not apply to transactions such as leases and decommissioning obligations. These transactions give rise to equal and offsetting temporary differences in which deferred tax should be recognized.

The amendments are effective for annual periods beginning on or after Jan. 1, 2023, with early application permitted. The Company's current position aligns with the amendment and no financial impact is therefore expected upon adoption on the effective date.

Amendments to IAS 1 Classification of Liabilities as Current or Non-Current

In October 2022, the IASB issued amendments to clarify how conditions with which an entity must comply within 12 months after the reporting period affect the classification of a liability, in addition to the amendment from January 2020 where the IASB issued amendments to IAS 1 Presentation of Financial Statements, to provide a more general approach to the presentation of liabilities as current or non-current based on contractual arrangements in place at the reporting date. These amendments specify that the rights and conditions existing at the end of the reporting period are relevant in determining whether the Company has a right to defer settlement of a liability by at least 12 months, provided that management's expectations are not a relevant consideration as to whether the Company will exercise its rights to defer settlement of a liability and clarify when a liability is considered settled.

The amendments are effective for annual periods beginning on or after Jan. 1, 2024, and are to be applied retrospectively. The Company has not yet determined the impact of these amendments on its consolidated financial statements.

Amendments to IFRS 16 Lease Liability in a Sale-and-Leaseback

In September 2022, the IASB issued Lease Liability in a Sale and Leaseback, which amends IFRS 16 Leases to provide additional specifications when subsequently measuring the lease liability that require the seller-lessee to determine lease payments and revised lease payments in a way that does not result in the seller-lessee recognizing any amount of the gain or loss that relates to the right of use it retains. The current effective date is Jan. 1, 2024. The Company is currently reviewing the impacts of this amendment on its consolidated financial statements.

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. Business Acquisitions

Acquisition of North Carolina Solar

On Nov. 5, 2021, the Company closed the acquisition of a 100 per cent membership interest in CI-II Mitchell Holding LLC, owner of a 122 MW portfolio of operating solar sites located in North Carolina (collectively, “North Carolina Solar”), for cash consideration of US$99 million (including working capital adjustments) and the assumption of existing tax equity obligations.

In accordance with IFRS 3 Business Combinations, the substance of the transactions described below constituted a business combination for TransAlta. The fair values of the identifiable assets and liabilities of the acquired entity in the business combinations as at the date of acquisition were:

	North Carolina Solar Nov. 5, 2021
Assets	
Cash and cash equivalents	4
Accounts receivable	4
Property, plant and equipment	146
Right-of-use assets	13
Liabilities	
Accounts payable and accrued liabilities	(4)
Lease liabilities	(13)
Tax equity liability	(20)
Deferred taxes	(3)
Decommissioning provisions	(4)
Net assets acquired	**123**
Cash consideration	**120**
Working capital consideration	**3**
Total purchase consideration transferred	**123**

In 2021, TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Company, acquired a 100 per cent economic interest in the North Carolina Solar facility from a wholly owned subsidiary of the Company through a tracking preferred share structure for aggregate consideration of approximately US$102 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of power, capacity and environmental attributes, leasing of power facilities and from asset optimization activities, which the Company disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	**33**	**220**	**462**	**10**	**—**	**—**	**725**
Environmental attributes(1)	**1**	**50**	**—**	**—**	**—**	**—**	**51**
Revenue from contracts with customers	**34**	**270**	**462**	**10**	**—**	**—**	**776**
Revenue from leases(2)	**—**	**—**	**32**	**—**	**—**	**—**	**32**
Revenue from derivatives and other trading activities(3)	**—**	**(87)**	**(821)**	**243**	**160**	**(2)**	**(507)**
Revenue from merchant sales	**564**	**86**	**1,529**	**461**	**—**	**—**	**2,640**
Other	**8**	**20**	**7**	**—**	**—**	**—**	**35**
Total revenue	**606**	**289**	**1,209**	**714**	**160**	**(2)**	**2,976**
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	**1**	**50**	**—**	**12**	**—**	**—**	**63**
Over time	**33**	**220**	**462**	**(2)**	**—**	**—**	**713**
Total revenue from contracts with customers	**34**	**270**	**462**	**10**	**—**	**—**	**776**

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.
(2) Total lease income from long-term contracts that meet the criteria of operating leases.
(3) Represents realized and unrealized gains or losses from hedging and derivative positions.

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	28	207	395	24	—	—	654
Environmental attributes(1)	—	28	—	—	—	—	28
Revenue from contracts with customers	28	235	395	24	—	—	682
Revenue from leases(2)	—	—	19	—	—	—	19
Revenue from derivatives and other trading activities(3)	—	(14)	(118)	138	211	4	221
Revenue from merchant sales	345	68	808	546	—	—	1,767
Other	10	16	5	1	—	—	32
Total revenue	383	305	1,109	709	211	4	2,721
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	28	2	23	—	—	53
Over time	28	207	393	1	—	—	629
Total revenue from contracts with customers	28	235	395	24	—	—	682

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.
(2) Total lease income from long-term contracts that meet the criteria of operating leases.
(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with current period.

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Revenues from contracts with customers							
Power and other	141	238	465	156	—	—	1,000
Environmental attributes[1]	—	23	—	—	—	—	23
Revenue from contracts with customers	141	261	465	156	—	—	1,023
Revenue from leases[2]	—	—	123	—	—	—	123
Revenue from derivatives and other trading activities[3]	—	8	(8)	283	122	12	417
Revenue from merchant sales	3	49	200	264	—	—	516
Other[4]	8	11	7	1	—	(5)	22
Total revenue	152	329	787	704	122	7	2,101
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	25	7	26	—	—	58
Over time	141	236	458	130	—	—	965
Total revenue from contracts with customers	141	261	465	156	—	—	1,023

(1) The environmental attributes represent environmental attribute sales not bundled with power and other sales.
(2) Total lease income from certain PPAs and long-term contracts that meet the criteria of operating leases.
(3) Represents realized and unrealized gains or losses from hedging and derivative positions. Wind and Solar has been revised to present revenue classifications consistent with current period.
(4) Includes government incentives and other miscellaneous.

B. Performance Obligations

The performance obligations in the Company's contracts with its customers include the provision of electricity and steam capacity; the delivery of electricity, thermal energy, environmental attributes; the provision of operation and maintenance services and water management services; and the supply of byproducts from coal generation.

The aggregate amount of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) as at Dec. 31, 2022, is approximately $2,790 million, with approximately $465 million expected to be recognized during the period 2023-2025; $490 million for the period of 2026-2028; $750 million for the period of 2029-2033; and $1,085 million for 2034 and thereafter.

These amounts exclude revenues related to contracts that qualify for the invoice practical expedient and future revenues that are related to constrained variable consideration. In many of the Company’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 Company’s influence. As a result, the amounts of future revenues disclosed above represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

6. Expenses by Nature

Fuel, Purchased Power and Operations, Maintenance and Administration ("OM&A")

Fuel and purchased power and OM&A expenses classified by nature are as follows:

Year ended Dec. 31	2022		2021		2020	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs	**578**	**—**	306	—	159	—
Coal fuel costs[1]	**141**	**—**	164	—	269	—
Royalty, land lease, other direct costs	**25**	**—**	19	—	20	—
Purchased power	**514**	**—**	339	—	163	—
Mine depreciation[2]	**—**	**—**	190	—	144	—
Salaries and benefits	**5**	**263**	36	234	50	235
Other operating expenses[3]	**—**	**258**	—	277	—	237
Total	**1,263**	**521**	1,054	511	805	472

(1) Included in coal fuel costs for 2021 and 2020 was $17 million and $15 million, respectively, related to the impairment of coal inventory.
(2) Included in mine depreciation for 2021 and 2020 was $48 million and $22 million, respectively, related to mine depreciation that was initially recorded in the standard cost of coal inventory and then subsequently written down during 2021.
(3) Included in OM&A costs for 2021 was $28 million related to the write-down of parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities.

7. Asset Impairment Charges

As part of the Company'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 Company 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 Company estimates a recoverable amount (the higher of value in use or fair value less costs of disposal) for the affected CGUs using discounted cash flow projections. The valuations are subject to measurement uncertainty from assumptions and inputs to the discount rates, power price forecasts, useful lives of the assets (extending to the last planned asset retirement in 2072) and long-range forecasts, which includes changes to production, fuel costs, operating costs and capital expenditures.

The Company recognized the following asset impairment charges (reversals):

For year ended Dec. 31	2022	2021	2020
Segments:			
Hydro	**21**	5	2
Wind and Solar	**43**	12	—
Gas	**—**	5	—
Energy Transition	**—**	540	82
Corporate	**(2)**	27	—
Changes in decommissioning and restoration provisions on retired assets[1]	**(53)**	32	—
Intangible asset impairment charges - coal rights[2]	**—**	17	—
Project development costs[3]	**—**	10	—
Asset impairment charges	**9**	648	84

(1) Changes relate to changes in discount rates and cash flow revisions on retired assets in 2022 and cash flow revisions on retired assets in 2021. Refer to Note 24 for further details.
(2) Impaired to nil in 2021, as no future coal will be extracted from this area of the mine.
(3) During 2021, the Company recorded an impairment charge of $9 million in the Hydro segment for the balance of project development costs at one of our hydro facilities as there is uncertainty on timing of when the project will proceed and $1 million related to projects that are no longer proceeding.

A. Hydro

During 2022, the Company recorded net impairment charges of $21 million on four hydro facilities as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The recoverable amounts of $89 million in total for these four assets were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement. The carrying value of property, plant & equipment, right-of-use assets and intangible assets for these Hydro facilities was $88 million as at Dec. 31, 2022.

B. Wind and Solar

During 2022, the Company recorded net impairment charges of $43 million on five wind facilities and one solar facility as a result of changes in key assumptions, that included significant increases in discount rates, changes in pricing and changes in estimated future cash flows. The recoverable amounts of $754 million for these six assets were estimated based on fair value less costs of disposal utilizing a discounted cash flow approach and are categorized as a Level III fair value measurement. The carrying value of property, plant & equipment, right-of-use assets and intangible assets for these Wind and Solar facilities was $748 million as at Dec. 31, 2022.

During 2021, the Company recorded impairment charges of $10 million for a wind asset as a result of an increase in estimated decommissioning costs after the review of an engineering study commissioned for the wind sites. The resulting fair value measurement less costs of disposal is categorized as a Level III fair value measurement and the Company adjusted the expected value down to $65 million using discount rates of 5.0 per cent.

Additionally, during 2021, the Company recognized impairment charges of $2 million related to the Kent Hills Wind LP tower failure. The Company's subsidiary, Kent Hills Wind LP, experienced a single tower failure at its 167 MW Kent Hills wind facility in Kent Hills, New Brunswick. The failure involved a collapsed tower located within the Kent Hills 2 site.

The calculation of fair value less costs of disposal for all of the above facilities is most sensitive to the following assumptions:

	Location of assets	Current year contract and merchant discount rates (1)	Prior year contract and merchant discount rates(1)
Wind and Solar	Canada	6.4 and 7.1 per cent	5.0 and 5.0 per cent
	US	6.5 and 7.7 per cent	5.1 and 5.0 per cent
Hydro	Canada	5.9 and 6.4 per cent	3.6 and 4.9 per cent

(1) Discount rates were related to the valuations performed for the Wind and Solar and Hydro segments in 2022. The prior year discount rates were related to the previous detailed valuation performed for the Wind and Solar segment in 2021 and for the Hydro segment in 2019.

C. Energy Transition

During 2021, the Company recognized asset impairment charges in the Energy Transition segment as a result of the decision to suspend the Sundance Unit 5 repowering project ($191 million) and planned retirements of Keephills Unit 1, effective Dec. 31, 2021 ($94 million), and Sundance Unit 4, effective April 1, 2022 ($56 million). Keephills Unit 1 and Sundance Unit 4 impairment assessments were based on the estimated salvage values of these units, which were in excess of the expected economic benefits from these units. For the Sundance Unit 5 repowering project, the recoverable amount was determined based on estimated fair value less costs of disposal of selling the assets under construction and estimated salvage value for the balance of the costs. The fair value measurement for assets under construction is categorized as a Level III fair value measurement. The total remaining estimated recoverable amount and salvage values for Sundance Unit 5 repowering project was $33 million. Discounting did not have a material impact to these asset impairments. The asset retirement and project suspension decisions were based on the Company's assessment of future market conditions, the age and condition of in-service units, as well as TransAlta's strategic focus toward renewable energy solutions.

During 2021, with the expected closure of the Highvale mine at the end of 2021, it was determined that the estimated salvage value exceeded the economic benefit to the Alberta Merchant CGU. The asset has been removed from the Alberta Merchant CGU for impairment purposes and was assessed for impairment as an individual asset, which resulted in the recognized impairment charge of $195 million in the Energy Transition segment, with the asset being written down to salvage value.

During 2020, the Company recognized impairment charges on Sundance Unit 3 in the amount of $70 million due to the Company's decision to retire the unit. 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 salvage value of the scrap materials. In addition, the Company recognized an impairment of $9 million (US$7 million) due to a decrease in the fair value of land for the Centralia mine determined through a third-party appraiser.

D. Corporate

Energy Transfer Canada, formerly SemCAMS Midstream ULC, purported to terminate the agreements related to the development and construction of the Kaybob Cogeneration Project. As a result, during the first quarter of 2021, the Company recorded impairment charges of $27 million in the Corporate segment as this facility was not yet operational. The recoverable amount was based on estimated fair value less costs of disposal of reselling the equipment purchased to date. During the fourth quarter of 2022, the dispute has been settled. The Company reversed $2 million of the impairment loss previously recognized.

8. Net Other Operating (Income) Loss

Net other operating (income) loss includes the following:

Year ended Dec. 31	2022	2021	2020
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Liquidated damages recoverable	**(12)**	—	—
Insurance recoveries	**(7)**	—	—
Supplier and other contract settlements	**5**	34	—
Onerous contract provisions	**—**	14	29
Retail power contract amortization (Note 27)	**(4)**	—	—
Net other operating (income) loss	**(58)**	8	(11)

A. Alberta Off-Coal Agreement ("OCA")

The Company receives payments from the Government of Alberta for the cessation of coal-fired emissions on or before Dec. 31, 2030. Under the terms of the agreement, the Company receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net of the non-controlling interest related to Sheerness), which commenced Jan. 1, 2017, and will terminate at the end of 2030. The Company 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, which has been achieved effective Dec. 31, 2021. 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.

B. Liquidated Damages Recoverable

During 2022, the Company recorded $12 million, related to requirements to be met by the contractor on turbine availability at the Windrise wind facility.

C. Insurance Recoveries

During 2022, the Company received insurance proceeds of $7 million related to the replacement costs for the single tower failure at the Kent Hills wind facilities.

D. Supplier and Other Contract Settlements

During 2022, $5 million was expensed related to contract settlements in the year.

During 2021, $34 million was expensed related to decisions to no longer proceed with the Sundance Unit 5 repowering project and to retire Keephills Unit 1, including a deferred asset of $10 million (US$8 million) for which the Company is unlikely to incur sufficient capital or operating expenditures to utilize the remaining credit.

E. Onerous Contract Provisions

During 2021, an onerous contract provision for future royalty payments of $14 million was recognized with the shutdown of the Highvale mine.

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

9. Investments

The change in investments is as follows:

	Skookumchuck	EMG	EIP	Ekona	Total
Classification	Equity-accounted	Equity-accounted	FVTPL	FVTOCI	
Balance, Dec. 31, 2020	85	15	—	—	100
Equity income (loss)	12	(3)	—	—	9
Distributions received	(4)	—	—	—	(4)
Balance, Dec. 31, 2021	93	12	—	—	105
Investment	**—**	**—**	**10**	**2**	**12**
Equity income (loss)	**10**	**(1)**	**—**	**—**	**9**
Distributions received	**(5)**	**—**	**—**	**—**	**(5)**
Changes in foreign exchange rates	**7**	**1**	**1**	**—**	**9**
Net change in fair value recognized in OCI	**—**	**—**	**—**	**(1)**	**(1)**
Balance, Dec. 31, 2022	**105**	**12**	**11**	**1**	**129**

Equity-accounted Investments

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

Skookumchuck Wind Project

TransAlta holds a 49 per cent membership interest in SP Skookumchuck Investment, LLC. Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state. The project has a 20-year PPA with Puget Sound Energy.

EMG International, LLC

TransAlta holds a 30 per cent membership interest in EMG. During 2022, the contingent purchase price consideration of US$3.5 million was paid, which was calculated based on actual earnings metrics achieved in 2021 and did not differ from the estimated amount included in the initial purchase price.

Summarized financial information on the results of operations relating to the Company's pro-rata interests in Skookumchuck and EMG, is as follows:

Year ended Dec. 31	2022	2021	2020
Results of operations			
Revenues and other operating income	**24**	19	3
Expenses	**(15)**	(10)	(2)
Proportionate share of net earnings	**9**	9	1

Other Investments

Energy Impact Partners

On May 6, 2022, the Company entered into a commitment to invest US$25 million over the next four years in Energy Impact Partners ("EIP") Deep Decarbonization Frontier Fund 1 (the "Frontier Fund"). The investment in the Frontier Fund provides the Company with a portfolio approach to investing in emerging technologies and the opportunity to identify, pilot, commercialize and bring to market emerging technologies that will facilitate the transition to net-zero emissions. During 2022, the Company invested $10 million (US$8 million). The investment is accounted for at FVTPL.

Ekona Power Inc.

On Feb. 1, 2022, the Company made an equity investment of $2 million in Ekona's Class B Preferred Shares. The investment will help support the commercialization of Ekona's novel methane pyrolysis technology platform, which produces cleaner and lower-cost turquoise hydrogen. The Company has irrevocably elected to measure its investment in Ekona at FVTOCI.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2022	2021	2020
Interest on debt	**164**	163	158
Interest on exchangeable debentures (Note 26)	**29**	29	29
Interest on exchangeable preferred shares (Note 26)	**28**	28	5
Interest income	**(24)**	(11)	(10)
Capitalized interest (Note 19)	**(16)**	(14)	(8)
Interest on lease liabilities	**7**	7	8
Credit facility fees, bank charges and other interest	**27**	20	25
Tax shield on tax equity financing (Note 25)[1]	**(2)**	(9)	1
Accretion of provisions (Note 24)	**49**	32	30
Net interest expense	**262**	245	238

(1) The credit balance in 2021 primarily relates to the tax benefit associated with investment tax credits claimed in 2021 on the North Carolina Solar facility that was assigned to the tax equity investor. The tax equity investments are treated as debt under IFRS and the monetization of the tax attributes is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliation

Year ended Dec. 31	2022	2021	2020
Earnings (loss) before income taxes	**353**	(380)	(303)
Net (earnings) loss attributable to non-controlling interests not subject to tax	**(94)**	(33)	2
Adjusted earnings (loss) before income taxes	**259**	(413)	(301)
Statutory Canadian federal and provincial income tax rate (%)	**23.4%**	23.6%	24.5%
Expected income tax expense (recovery)	**61**	(98)	(74)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**(1)**	4	3
Non-deductible expense[1]	**130**	—	—
Taxable capital gain	**18**	—	—
Deferred income tax expense (recovery) related to temporary difference on investment in subsidiaries	**(2)**	—	9
Write-down (reversal of write-down) of unrecognized deferred income tax assets	**(24)**	134	8
Statutory and other rate differences	**(3)**	4	(7)
Adjustments in respect of deferred income tax of previous years[2]	**6**	(4)	(3)
Other[2]	**7**	5	14
Income tax expense (recovery)	**192**	45	(50)
Effective tax rate (%)	**74%**	(11%)	17%

(1) This amount is related to current and prior period tax adjustments in the US to mitigate cash tax relating to the Base Erosion and Anti-Abuse Tax ("BEAT").
(2) During 2022, the 2021 and 2020 amounts were reclassified from Other to Adjustments in respect of deferred income tax of previous years to better represent the nature of items impacting income tax expense (recovery). These reclassifications did not impact prior years' total income tax expense (recovery) or net earnings (loss).

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2022	2021	2020
Current income tax expense	**65**	56	35
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**153**	(145)	(95)
Deferred income tax expense (recovery) related to temporary difference on investment in subsidiary	**(2)**	—	9
Deferred income tax recovery resulting from changes in tax rates or laws	**—**	—	(7)
Deferred income tax expense (recovery) arising from the unrecognized deferred income tax assets[1]	**(24)**	134	8
Income tax expense (recovery)	**192**	45	(50)

Year ended Dec. 31	2022	2021	2020
Current income tax expense	**65**	56	35
Deferred income tax expense (recovery)	**127**	(11)	(85)
Income tax expense (recovery)	**192**	45	(50)

(1) During the year ended Dec. 31, 2022, the Company recognized deferred tax assets of $24 million (2021 – $134 million write-down, 2020 – $8 million write-down). The deferred income tax assets mainly relate to the tax benefits associated with tax losses related to the Company's directly owned US operations and other deductible differences. The Company has not recognized $361 million of deferred tax assets on the basis that it is not probable that sufficient future taxable income would be available to utilize these tax assets. The Company undertakes an analysis of the recoverability of its tax assets on an annual basis.

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	2022	2021	2020
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(112)**	(57)	(23)
Net impact related to hedges of foreign operations	**(3)**	—	—
Net impact to net actuarial gains (losses)	**12**	11	(3)
Income tax recovery reported in equity	**(103)**	(46)	(26)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2022	2021
Non-capital losses[1]	**244**	530
Future decommissioning and restoration costs	**119**	183
Property, plant and equipment	**(553)**	(651)
Risk management assets and liabilities, net	**193**	(53)
Employee future benefits and compensation plans	**48**	53
Interest deductible in future periods	**—**	17
Foreign exchange differences on US-denominated debt	**13**	16
Other deductible temporary differences	**(5)**	(5)
Net deferred income tax asset, before write-down of deferred income tax assets	**59**	90
Unrecognized deferred income tax assets	**(361)**	(380)
Net deferred income tax liability, after write-down of deferred income tax assets	**(302)**	(290)

(1) Non-capital losses expire between 2033 and 2042. Net operating losses from US operations have no expiration.

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

As at Dec. 31	2022	2021
Deferred income tax assets[1]	**50**	64
Deferred income tax liabilities	**(352)**	(354)
Net deferred income tax liability	**(302)**	(290)

(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 Company's long-range forecasts.

D. Contingencies

As of Dec. 31, 2022, the Company had recognized a net liability of nil (2021 – nil) related to uncertain tax positions.

In 2022, the Canada Revenue Agency completed its examination of the Company's tax filings for the 2015 taxation year, including its review of an internal reorganization completed in 2015. Upon conclusion of the 2015 audit, no reassessment was issued.

12. Non-Controlling Interests

The Company's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2022
TransAlta Cogeneration LP	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, LP ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a dual-fuel generating facility.

TransAlta Renewables ("RNW") 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 Company. Kent Hills Wind LP, a subsidiary of TransAlta Renewables, owns and operates the 167 MW Kent Hills (1, 2 and 3) wind facilities located in New Brunswick.

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 Kent Hills Wind LP.

Year ended Dec. 31	**2022**	2021	2020
Revenues	**560**	470	436
Net earnings	**74**	139	97
Total comprehensive income (loss)	**(67)**	66	223
Amounts attributable to the non-controlling interests:			
Net earnings	**20**	50	40
Total comprehensive income (loss)	**(36)**	21	90
Distributions paid to non-controlling interests	**100**	100	80

As at Dec. 31	**2022**	2021
Current assets	**240**	430
Long-term assets	**2,989**	3,319
Current liabilities	**(306)**	(593)
Long-term liabilities	**(1,118)**	(1,033)
Total equity	**(1,805)**	(2,123)
Equity attributable to non-controlling interests	**(732)**	(869)
Non-controlling interests' share (per cent)	**39.9**	39.9

B. TA Cogen

Year ended Dec. 31	2022	2021	2020
Revenues	**347**	265	146
Net earnings (loss)	**143**	103	(13)
Total comprehensive income (loss)	**143**	103	(13)
Amounts attributable to the non-controlling interest:			
Net earnings (loss)	**91**	62	(6)
Total comprehensive income (loss)	**91**	62	(6)
Distributions paid to Canadian Power Holdings Inc.	**87**	56	17

As at Dec. 31	2022	2021
Current assets	**127**	66
Long-term assets	**253**	312
Current liabilities	**(62)**	(52)
Long-term liabilities	**(27)**	(36)
Total equity	**(291)**	(290)
Equity attributable to Canadian Power Holdings Inc.	**(147)**	(142)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables and Accounts Payable

As at Dec. 31	2022	2021
Trade accounts receivable	**1,165**	499
Collateral provided (Note 15)	**304**	55
Current portion of finance lease receivables (Note 17)	**52**	40
Loan receivable (Note 23)	**4**	55
Income taxes receivable	**64**	2
Trade and other receivables	**1,589**	651

As at Dec. 31	2022	2021
Accounts payable and accrued liabilities	**1,069**	654
Interest payable	**17**	17
Collateral held (Note 15)	**260**	18
Accounts payable and accrued liabilities	**1,346**	689

14. Financial Instruments

A. Financial Assets and Liabilities — Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2022	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Other financial assets (FVTOCI)	Total
Financial assets						
Cash and cash equivalents[1]	—	—	1,134	—	—	1,134
Restricted cash	—	—	70	—	—	70
Trade and other receivables	—	—	1,589	—	—	1,589
Long-term portion of finance lease receivables	—	—	129	—	—	129
Long-term portion of loan receivable[2]	—	—	33	—	—	33
Other investments	—	—	—	11	1	12
Risk management assets						
Current	—	709	—	—	—	709
Long-term	—	161	—	—	—	161
Financial liabilities						
Bank overdraft	—	—	16	—	—	16
Accounts payable and accrued liabilities	—	—	1,346	—	—	1,346
Dividends payable	—	—	68	—	—	68
Risk management liabilities						
Current	271	858	—	—	—	1,129
Long-term	76	257	—	—	—	333
Credit facilities, long-term debt and lease liabilities[3]	—	—	3,653	—	—	3,653
Exchangeable securities	—	—	739	—	—	739

(1) Includes cash equivalents of nil.
(2) Included in other assets. Refer to Note 23.
(3) Includes current portion.

Carrying value as at Dec. 31, 2021	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	—	—	947	947
Restricted cash	—	—	70	70
Trade and other receivables	—	—	651	651
Long-term portion of finance lease receivables	—	—	185	185
Risk management assets				
Current	36	272	—	308
Long-term	252	147	—	399
Financial liabilities				
Accounts payable and accrued liabilities	—	—	689	689
Dividends payable	—	—	62	62
Risk management liabilities				
Current	—	261	—	261
Long-term	—	145	—	145
Credit facilities, long-term debt and lease liabilities[2]	—	—	3,267	3,267
Exchangeable securities	—	—	735	735

(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 when selling the asset or paid to transfer the associated liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by observing quoted prices for the instrument in active markets to which the Company has access. In the absence of an active market, the Company 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 Company looks primarily to external readily observable market inputs. However, if not available, the Company 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 Company 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. The Level III classification is the lowest level classification in the fair value hierarchy.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. In determining Level I fair values, the Company 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 Company'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 Company 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 Company 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 Company 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 scenario analysis simulation 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 volatility and correlations between products derived from historical price relationships. For assets and liabilities that are recognized at fair value on a recurring basis, the Company determines whether transfers have occurred between levels in the hierarchy by re-assessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

The Company 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.

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 segments 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, 2022, are as follows: Level I – $23 million net asset (2021 – $12 million net asset), Level II – $173 million net asset (2021 – $122 million net asset) and Level III – $782 million net liability (2021 – $159 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2022, are primarily attributable to volatility in market prices across multiple markets on both existing contracts and new contracts as well as contract settlements.

The following table summarizes the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification during the years ended Dec. 31, 2022 and 2021, respectively:

	Year ended Dec. 31, 2022			Year ended Dec. 31, 2021		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**285**	**(126)**	**159**	573	9	582
Changes attributable to:						
Market price changes on existing contracts	**(611)**	**(298)**	**(909)**	(181)	4	(177)
Market price changes on new contracts	**—**	**(124)**	**(124)**	—	(134)	(134)
Contracts settled	**(38)**	**118**	**80**	(107)	(5)	(112)
Change in foreign exchange rates	**17**	**(5)**	**12**	—	—	—
Net risk management assets (liabilities) at end of year	**(347)**	**(435)**	**(782)**	285	(126)	159
Additional Level III information:						
Losses recognized in other comprehensive loss	**(594)**	**—**	**(594)**	(181)	—	(181)
Total gains (losses) included in earnings (loss) before income taxes	**38**	**(427)**	**(389)**	107	(130)	(23)
Unrealized gains (losses) included in earnings (loss) before income taxes relating to net assets held at year end	**—**	**(309)**	**(309)**	—	(135)	(135)

The Company 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.

The Company's risk management department determines methodologies and procedures regarding commodity risk management Level III fair value measurements. Level III fair values are primarily calculated within the Company'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.

As at Dec. 31, 2022, the total Level III risk management asset balance was $31 million (2021 – $305 million) and Level III risk management liability balance was $813 million (2021 – $146 million). The fair value of the level III long-term power sale - US contract as well as the long-term wind energy sales contracts have decreased mainly due to higher projected market prices within the next two years. The 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 are outlined in the following table. These include the effects on fair value of discounting, liquidity and credit value adjustments; however, the potential offsetting effects of Level II positions are not considered. 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, volatility in commodity prices and correlations, delivery volumes, escalation rates and cost of supply.

As at		Dec. 31, 2022		
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonably possible change**
Long-term power sale – US	+15 -163	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$55
Coal transportation – US	+14 -13	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$5 or price increase of US$55
			Volatility	80% to 120%
			Rail rate escalation	zero to 10%
Full requirements – Eastern US	+3 -21	Scenario analysis[1]	Volume	96% to 104%
			Cost of supply	Decrease of $0.50 per MWh or increase of $3.30 per MWh
Long-term wind energy sale – Eastern US	+22 -18	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$6
			Illiquid future REC prices (per unit)	Price decrease or increase of US$2
			Wind discounts	0% decrease or 5% increase
Long-term wind energy sale – Canada	+47 -25	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$85 or increase of C$5
			Wind discounts	28% decrease or 5% increase
Long-term wind energy sale - Central US	+74 -28	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease or increase of US$2
			Wind discounts	2% decrease or 5% increase
Others	+18 -19			

(1) The valuation technique for Full requirements - Eastern US was updated to scenario analysis to provide a more representative description and did not result in changes to the value.

As at			Dec. 31, 2021	
Description	Sensitivity	Valuation technique	Unobservable input	Reasonably possible change
Long-term power sale – US	+22 -145	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or a price increase of US$20
Coal transportation – US	+3 -18	Numerical derivative valuation	Illiquid future power prices (per MWh)	Price decrease of US$3 or a price increase of US$20
			Volatility	80% to 120%
			Rail rate escalation	zero to 4%
Full requirements – Eastern US	+9 -9	Historical Bootstrap	Volume	95% to 105%
			Cost of supply	(+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+17 -16	Long-term price forecast	Illiquid future power prices (per MWh)	Price increase or decrease of US$6
			Illiquid future REC prices (per unit)	Price decrease US$3 or increase of US$2
Long-term wind energy sale – Canada	+21 -11	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of C$24 or increase of C$5
			Wind discounts	5% decrease or 5% increase
Long-term wind energy sale – Central US	+27 -15	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$2 or increase of US$3
			Wind discounts	3% decrease or 3% increase
Others	+6 -6			

i. Long-Term Power Sale – US

The Company 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 2024, 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).

The contract is denominated in US dollars. The US dollar relative to the Canadian dollar strengthened from Dec. 31, 2021, to Dec. 31, 2022, resulting in a decrease in the base fair value and an increase in the sensitivity values by approximately $21 million and $9 million, respectively. The fair value of this contract at Dec. 31, 2022, decreased mainly due to higher forward power prices compared to previously estimated prices.

ii. Coal Transportation – US

The Company has a coal rail transport agreement that includes an upside sharing mechanism until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the agreement.

The key unobservable inputs used in the valuation include non-liquid power prices, option volatility and rail rate escalation. For periods beyond 2024, 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 judgment.

iii. Full Requirements – Eastern US

The Company has a portfolio of full requirement service contracts, whereby the Company agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits ("RECs") 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.

iv. Long-Term Wind Energy Sale – Eastern US

The Company entered into a long-term contract for differences ("CFD") for the offtake of 100 per cent of the generation from its 90 MW Big Level wind facility. The CFD, together with the sale of electricity generated into the PJM Interconnection at the prevailing real-time energy market price, achieve the fixed contract price per MWh on proxy generation. Under the CFD, if the market price is lower than the fixed contract price the customer pays the company the difference and if the market price is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The contract matures in December 2034. The contract is accounted for as a derivative. Changes in fair value are presented in revenue.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power, RECs and wind discounts.

v. Long-Term Wind Energy Sale – Canada

The Company entered into two VPPAs for the offtake of 100 per cent of the generation from its 130 MW Garden Plain wind project. The VPPAs, together with the sale of electricity generated into the Alberta power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price the customer pays the Company the difference and if the pool price is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. Both VPPAs commence on commercial operation of the facility and extend for a weighted average of approximately 17 years. The commercial operation date is expected to be in 2023.

In addition to the VPPAs, the Company has entered into a bridge contract that initially was for 16 months from Sept. 1, 2021, through Dec. 31, 2022, and will remain in effect at one of the VPPAs price until the commercial operation date is achieved. The customer is also entitled to the physical delivery of environmental attributes.

The energy component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue.

The key unobservable inputs used in the valuations of the contracts are the non-liquid forward prices for power and monthly wind discounts.

Under a separate agreement, Pembina Pipeline Corporation ("Pembina") has the option to purchase a 37.7 per cent equity interest in the project. The option can be exercised no later than 30 days after Pembina receives notice of the commercial operational date.

vi. Long-Term Wind Energy Sale – Central US

The Company entered into two long-term VPPAs for the offtake of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects. The VPPAs, together with the sale of electricity generated into the US Southwest power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPAs, if the pool price is lower than the fixed contract price the customer pays the Company the difference and if the pool price is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPAs commence on commercial operation of the facilities, which is expected within the second half of 2023.

The Company entered into a long-term VPPA for the offtake of 100 per cent of the generation from its 200 MW Horizon Hill wind project. The VPPA, together with the sale of electricity generated into the US Southwest power market at the pool price, achieve the fixed contract prices per MWh. Under the VPPA, if the pool price is lower than the fixed contract price the customer pays the Company the difference and if the pool price is higher than the fixed contract price the Company refunds the difference to the customer. The customer is also entitled to the physical delivery of environmental attributes. The VPPA commences on commercial operation of the facility, which is expected within the second half of 2023.

The energy component of these contracts is accounted for as derivatives. Changes in fair value are presented in revenue.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and wind discounts.

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 $6 million as at Dec. 31, 2022 (2021 – $8 million net asset) are classified as Level II fair value measurements. The changes in other net risk management assets and liabilities during the year ended Dec. 31, 2022, are primarily attributable to unfavourable market price changes on existing contracts and unfavourable foreign exchange rates on new contracts entered into during 2022.

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 value(1)
	Level I	Level II	Level III	Total	
Exchangeable securities — Dec. 31, 2022	**—**	**685**	**—**	**685**	**739**
Long-term debt — Dec. 31, 2022	**—**	**3,200**	**—**	**3,200**	**3,518**
Loan receivable — Dec. 31, 2022	**—**	**37**	**—**	**37**	**37**
Exchangeable securities — Dec. 31, 2021	—	770	—	770	735
Long-term debt — Dec. 31, 2021	—	3,272	—	3,272	3,167
Loan receivable — Dec. 31, 2021	—	55	—	55	55

(1) Includes current portion.

The fair values of the Company'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 provided, bank overdraft, accounts payable and accrued liabilities, collateral held and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the finance lease receivables (see Note 17) approximate the carrying amounts as the amounts receivable represent cash flows from repayments of principal and interest.

C. Inception Gains and Losses

The majority of derivatives traded by the Company are based on adjusted quoted prices on an active exchange or extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using inputs that are not readily observable. Refer to section B of this Note 14 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings (loss) and a reconciliation of changes is as follows:

As at Dec. 31	2022	2021	2020
Unamortized net gain (loss) at beginning of year(1)	**(131)**	(33)	9
New inception loss(2)	**(37)**	(79)	(13)
Change in foreign exchange rates	**(10)**	—	—
Amortization recorded in net earnings during the year	**(35)**	(19)	(29)
Unamortized net loss at end of year	**(213)**	(131)	(33)

(1) In 2022, the day one valuation of certain PPAs in 2021 was revised for consistency with other fair value calculations. The reconciliation for the 2021 comparative period was restated. This did not impact the prior year financial statements as the inception completely offset the fair value at Dec. 31, 2021.

(2) During 2022, the Company entered into a PPA for the Horizon Hill wind project (2021 – PPAs for the White Rock wind project) that resulted in a new inception loss due to the difference between the fixed PPA price and future estimated market prices. There are other key factors, such as project economics and incentives, that influence the long-term power price for renewable projects outside of the power price curve, which is not liquid for the majority of the duration of the PPA. During 2020, the Company 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.

15. Risk Management Activities

A. Risk Management Strategy

The Company is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Company's earnings and the value of associated financial instruments that the Company holds. In certain cases, the Company seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Company's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Company's internal objectives and its risk tolerance.

The Company 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 Company 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 Company may apply hedge accounting to those hedging commodity price risk, interest rate risk and foreign currency risk.

The use of financial derivatives is governed by the Company'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 Company 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 Company 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 Company 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 Company 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 Company 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 Company 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 (liabilities) are as follows:

As at Dec. 31, 2022	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	**(271)**	**(143)**	**(414)**
Long-term	**(76)**	**(96)**	**(172)**
Net commodity risk management liabilities	**(347)**	**(239)**	**(586)**
Other			
Current	—	**(6)**	**(6)**
Long-term	—	—	—
Net other risk management liabilities	—	**(6)**	**(6)**
Total net risk management liabilities	**(347)**	**(245)**	**(592)**

As at Dec. 31, 2021	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	33	12	45
Long-term	252	(4)	248
Net commodity risk management assets	285	8	293
Other			
Current	3	(1)	2
Long-term	—	6	6
Net other risk management assets	3	5	8
Total net risk management assets	288	13	301

Netting Arrangements

Information about the Company's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31, 2022	**Gross amounts of recognized financial assets (liabilities)**	**Amounts set off**	**Net amounts presented on the statement of financial position**	**Master netting arrangements[1]**	**Net amount**
Current risk management assets	**$ 1,602**	**$ (883)**	**$ 688**	**$ (62)**	**$ 626**
Long-term risk management assets	**$ 204**	**$ (43)**	**$ 157**	**$ (7)**	**$ 150**
Current risk management liabilities	**$ (1,953)**	**$ 883**	**$ (1,033)**	**$ 62**	**$ (971)**
Long-term risk management liabilities	**$ (449)**	**$ 43**	**$ (402)**	**$ 7**	**$ (395)**
Trade and other receivables[2]	**$ 1,330**	**$ (934)**	**$ 396**	**$ (176)**	**$ 220**
Accounts payable and accrued liabilities[2]	**$ (1,344)**	**$ 934**	**$ (411)**	**$ 176**	**$ (235)**

As at Dec. 31, 2021	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the statement of financial position	Master netting arrangements[1]	Net amount
Current risk management assets	$ 636	$ (307)	$ 316	$ (92)	$ 224
Long-term risk management assets	$ 285	$ (16)	$ 260	$ (23)	$ 237
Current risk management liabilities	$ (529)	$ 307	$ (211)	$ 92	$ (119)
Long-term risk management liabilities	$ (89)	$ 16	$ (70)	$ 23	$ (47)
Trade and other receivables[2]	$ 699	$ (571)	$ 128	$ (35)	$ 93
Accounts payable and accrued liabilities[2]	$ (689)	$ 571	$ (118)	$ 35	$ (83)

(1) Amounts not set off in the Consolidated Statements of Financial Position.
(2) The trade and other receivables and accounts payable and accrued liabilities include amounts related to collateral provided and held. Refer to Note 15(F) below for further details.

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Company 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 Company'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 Company'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 Company's proprietary trading business, the VPPAs and other long-term contracts that are derivatives and commodity derivatives used in hedging relationships associated with the Company's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Company uses three tools:

- A framework of risk controls;
- A predefined 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 Company has executed commodity price hedges for its Centralia thermal facility, including a long-term physical power sale contract, and may, at times, execute hedges for its portfolio of merchant power exposure in Alberta using fixed price financial swaps or other similar instruments. Both hedging strategies fall under the Company's risk management strategy used to hedge commodity price risk.

Market risk exposures are measured using Value at Risk ("VaR") supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured. Position sizes and trade strategies were adjusted to remain within the Company's risk framework.

i. Commodity Price Risk Management – Proprietary Trading

The Company'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 Company'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, 2022, associated with the Company's proprietary trading activities was $4 million (2021 – $2 million, 2020 – $1 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 Company'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 Company's reported net earnings.

VaR at Dec. 31, 2022, associated with the Company's commodity derivative instruments used in generation hedging activities was $97 million (2021 – $33 million, 2020 – $12 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, 2022, associated with these transactions was $54 million (2021 – $51 million, 2020 – $15 million), of which $26 million related to VPPAs (2021 – $14 million, 2020 – $3 million).

iii. Commodity Price Risk Management – Hedges

At Dec. 31, 2022, the Company had no outstanding commodity derivative instruments designated as hedging instruments, except for the long-term power sale - US contract. For further details on this contract, refer to Note 14(B)(II)(i).

iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	2022		2021	
Type (thousands)	Notional amount sold	Notional amount purchased	Notional amount sold	Notional amount purchased
Electricity (MWh)	**55,821**	**13,934**	46,139	14,951
Natural gas (GJ)	**23,464**	**162,384**	7,501	173,898
Transmission (MWh)	**—**	**1,643**	37	1,097
Emissions (MWh)	**274**	**2,297**	445	2,030
Emissions (tonnes)	**300**	**300**	350	350
Coal (tonnes)	**—**	**7,746**	—	9,352

b. Interest Rate Risk Management

Changes in interest rates can impact the Company's borrowing costs and cost of capital. Changes in the cost of capital could affect the feasibility of new growth initiatives. Interest rate risk also arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates.

The Company's credit facility, Term Facility ("Term Facility") and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 15 per cent of the Company's total long-term debt as at Dec. 31, 2022 (2021 – 3 per cent). Interest rate risk is managed with the use of derivatives.

The Company's outstanding interest rate derivative instruments are as follows:

The Company entered into two interest rate swaps agreements in October 2022 for $100 million each to manage interest rate risk related to a portion of its Term Facility. The Company pays a fixed blended rate of 4.70 per cent and receives one month Canadian Dollar Offered Rate ("CDOR") that resets monthly. The maturity date is Nov. 10, 2023.

Interest rate swap agreements with a notional amount of US$150 million referencing the three-month London Interbank Offered Rate were replaced with swap agreements referencing the Secured Overnight Financing Rate ("SOFR"). These swaps were settled in 2022. In addition, the US$150 million bond lock agreement outstanding at Dec. 31, 2021, was settled in 2022.

Interbank Offered Rate reform could impact interest rate risk with respect to the Company's credit facilities and the Poplar Creek non-recourse bond held by a TransAlta subsidiary. The credit facilities with $433 million outstanding (2021 – nil) reference the CDOR for Canadian-dollar drawings, but include appropriate fallback language to replace this benchmark rate in the event of a benchmark transition. The Poplar Creek non-recourse bond with a face value as at Dec. 31, 2022 of $95 million (2021 – $104 million) pays interest based upon the three-month CDOR. Cessation of the three-month CDOR is anticipated to occur mid-2024.

c. Currency Rate Risk

The Company 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 Company 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 Company'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 Company's net investment in foreign subsidiaries, the Company 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 Company'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 (2021 – US$370 million).

ii. Non-Hedges

The Company also uses foreign currency contracts to manage its expected foreign operating cash flows and foreign exchange forward contracts to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31		**2022**				2021	
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							
AU183	**CAD168**	**(1)**	**2023-2026**	AU28	CAD26	(5)	2022-2025
US573	**CAD761**	**(12)**	**2023-2025**	US271	CAD357	8	2022-2025
US66	**AU102**	**4**	**2023**	—	—	—	—
Foreign exchange forward contracts – foreign-denominated debt							
CAD159	**US120**	**3**	**2023**	CAD191	US150	1	2022

iii. 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 Company's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cents (2021 – three cents, 2020 – three cents) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2022		2021		2020	
Currency	Net earnings decrease(1)	OCI gain (1)(2)	Net earnings increase (decrease)(1)	OCI gain (1)(2)	Net earnings decrease(1)	OCI gain (1)(2)
USD	**(12)**	**—**	(13)	1	(8)	1
AUD	**(2)**	**—**	1	—	(4)	—
Total	**(14)**	**—**	(12)	1	(12)	1

(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 Company by failing to discharge their obligations and the risk to the Company associated with changes in creditworthiness of entities with which commercial exposures exist. The Company 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 Company 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 Company 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 Company 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 Company's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2022:

	Investment grade (Per cent)	Non-investment grade (Per cent)	Total (Per cent)	Total amount
Trade and other receivables(1)(2)	87	13	100	**1,585**
Long-term finance lease receivable	100	—	100	**129**
Risk management assets(1)	92	8	100	**870**
Loan receivable(2)	—	100	100	**37**
Total				**2,621**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes $37 million loan receivable included within other assets with a counterparty that has no external credit rating. The current portion of $4 million was excluded from trade and other receivables as it is included in loan receivable in the table above. Refer to Note 23 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 Company did not have significant expected credit losses as at Dec. 31, 2022.

The Company's maximum exposure to credit risk at Dec. 31, 2022, 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, 2022, was $64 million (2021 – $37 million).

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for capital projects, debt refinancing, proprietary trading activities, commodity hedging and general corporate purposes. As at Dec. 31, 2022, TransAlta maintains an investment grade rating from one credit rating agency and below investment grade ratings from two credit rating agencies. Between 2023 and 2025, the Company has approximately $839 million of debt maturing, comprised of approximately $400 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments.

Collateral is posted based on negotiated terms with counterparties, which can include the Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company'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 Audit, Finance and Risk Committee (on behalf of the Board); and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Company does not use derivatives or hedge accounting to manage liquidity risk.

A maturity analysis of the Company's financial liabilities as well as financial assets that are expected to generate cash inflows to meet cash outflows on financial liabilities, is as follows:

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Bank overdraft	16	—	—	—	—	—	16
Accounts payable and accrued liabilities	1,346	—	—	—	—	—	1,346
Long-term debt(1)							
Credit facilities(1)	—	400	—	33	—	—	433
Debentures	—	—	—	—	—	251	251
Senior notes	—	—	—	—	—	949	949
Non-recourse — Hydro	45	—	—	—	—	—	45
Non-recourse — Wind & Solar	63	66	69	67	70	363	698
Non-recourse — Gas	45	46	58	61	65	782	1,057
Tax equity financing	16	15	15	16	19	48	129
Other	1	—	—	—	—	—	1
Exchangeable securities(2)	—	—	750	—	—	—	750
Commodity risk management (assets) liabilities	415	182	(42)	15	8	8	586
Other risk management (assets) liabilities	7	(1)	1	—	—	(1)	6
Lease liabilities(3)	(7)	4	4	3	4	127	135
Interest on long-term debt and lease liabilities(4)	205	192	166	158	150	836	1,707
Interest on exchangeable securities(2)(4)	52	62	—	—	—	—	114
Dividends payable	68	—	—	—	—	—	68
Total	**2,272**	**966**	**1,021**	**353**	**316**	**3,363**	**8,291**

(1) Excludes impact of hedge accounting and derivatives.
(2) The exchangeable securities can be exchanged, at the earliest, on Jan. 1, 2025. Refer to Note 26 for further details.
(3) Lease liabilities include a lease incentive of $12 million expected to be received in 2023.
(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

Total Return Swaps

The Company has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Company. The Company 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 Company'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					
	2023	2024	2025	2026	2027	2028
Cash flow hedges						
Commodity derivative instruments						
Electricity						
Notional amount (thousands of MWh)	3,329	3,338	2,628	—	—	—
Average price ($ per MWh)	78.27	80.22	82.22	—	—	—

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, 2022	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[(1)]	**9,295**	**(347)**	**Risk management liabilities**	**(594)**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	**US370**	**CAD502**	**Credit facilities, long-term debt and lease liabilities**	**—**

(1) In thousands of MWh.

As at Dec. 31, 2021	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[(1)]	12,624	285	Risk management assets	(181)
Interest rate risk				
Cash flow hedges				
Interest rate swap	US300	3	Risk management assets	3
Foreign currency risk				
Cash flow hedges				
Foreign-denominated expenditures	US8	—	Risk management assets	—
Foreign-denominated expenditures	US14	—	Risk management assets	—
Net investment hedges				
Foreign-denominated debt	US370	CAD473	Credit facilities, long-term debt and lease liabilities	—

(1) In thousands of MWh.

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31	2022		2021	
	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	**(594)**	**(279)**	(181)	226
Interest rate risk				
Cash flow hedges				
Interest expense on long-term debt	**—**	**—**	3	2
	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	**—**	**(39)**	—	(35)

(1 Net of tax. Included in AOCI.

The hedging gain or loss 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 designated cash flow hedges on OCI and net earnings is:

Year ended Dec. 31, 2022					
	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	**(747)**	Revenue	**124**	Revenue	**—**
Forward starting interest rate swaps	**53**	Interest expense	**2**	Interest expense	**—**
OCI impact	**(694)**	**OCI impact**	**126**	**Net earnings impact**	**—**

Over the next 12 months, the Company estimates that approximately $208 million of after-tax losses 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, 2021					
	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	(268)	Revenue	(13)	Revenue	—
Foreign exchange forwards on project hedges	—	Property, plant and equipment	1	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	13	Interest expense	4	Interest expense	—
OCI impact	(255)	OCI impact	(8)	Net earnings impact	—

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	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2022, the Company recognized a net unrealized loss of $384 million (2021 – gain of $97 million, 2020 – gain of $43 million) related to commodity derivatives.

For the year ended Dec. 31, 2022, a gain of $20 million (2021 – gain of $6 million, 2020 – gain of $11 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized losses of $11 million (2021 – gain of $4 million, 2020 – loss of $2 million) and net realized gains of $31 million (2021 – gains of $2 million, 2020 — gains of $13 million), respectively.

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2022, the Company provided $304 million (2021 — $55 million) in cash and cash equivalents as collateral to regulated clearing agents and certain utility customers as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. The utility customers are obligated to pay interest on the outstanding balances. Collateral provided is included within trade and other receivables in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2022, the Company held $260 million (2021 – $18 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Company 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 related to physical and financial derivative transactions in a net asset position and is included in accounts payable and accrued liabilities 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 Company's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Company's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs. At Dec. 31, 2022, the Company had posted collateral of $820 million (2021 – $356 million) in the form of letters of credit on physical and financial derivative transactions in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $656 million (2021 – $120 million) of collateral to its counterparties.

16. Inventory

The components of inventory are as follows:

As at Dec. 31	2022	2021
Parts, materials and supplies	**83**	82
Coal	**43**	27
Emission credits	**27**	55
Natural gas	**4**	3
Total	**157**	167

No inventory is pledged as security for liabilities.

During 2022, coal inventory increased primarily due to higher coal inventory volume at Centralia Unit 2 along with higher coal pricing.

As at Dec. 31, 2022, the Company holds 963,068 emission credits in inventory purchased externally with a recorded book value of $27 million (Dec. 31, 2021 – 2,033,752 emission credits with a recorded book value of $55 million). The Company also has approximately 1,869,450 (Dec. 31, 2021 – 1,922,973) of internally generated eligible emission credits from the Company's Wind and Solar and Hydro segments with no recorded book value. These emission credits can be used to offset future emission obligations from our gas facilities located in Canada where the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. In addition, the Company holds approximately 1,750,000 (Dec. 31, 2021 – 1,750,000) eligible emission performance credits ("EPCs") with no recorded book value generated from assets formerly subject to the Hydro Power Purchase Arrangement ("Hydro PPA") during the year. The Balancing Pool is asserting ownership of these EPCs, which the Company has disputed through an arbitration to be heard in May 2023. Refer to Note 37 for further details.

During 2022, the Company utilized 1,169,333 emission credits with a carrying value of $35 million to settle the 2021 carbon compliance obligation of $47 million. The difference of $12 million has been recognized as a reduction in the Company's carbon compliance costs in the year.

17. Finance Lease Receivables

Amounts receivable under the Company's finance leases associated with the Poplar Creek cogeneration facility and the Southern Cross Energy facilities are as follows:

As at Dec. 31	2022		2021	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**62**	**55**	58	54
Second to fifth years inclusive	**81**	**75**	127	105
More than five years	**60**	**51**	80	66
	203	**181**	265	225
Less: unearned finance lease income	**22**	**—**	40	—
Total finance lease receivables	**181**	**181**	225	225
Included in the Consolidated Statements of Financial Position as:				
Current portion of finance lease receivables (Note 13)	**52**		40	
Long-term portion of finance lease receivables	**129**		185	
Total finance lease receivables	**181**		225	

18. Assets Held for Sale

The change in assets held for sale is as follows:

	2022	2021
Balance, Jan 1	**25**	105
Transfers from property, plant and equipment	**28**	25
Disposals	**(31)**	(105)
Balance, Dec. 31	**22**	25

Sale of Pioneer Pipeline

On Oct. 1, 2020, the Company 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"). At Jan. 1, 2021, the assets held for sale included our interest in the Pioneer Pipeline and certain mining assets.

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO for the aggregate sale price of $255 million. The net cash proceeds to the Company from the sale of its 50 per cent interest, were approximately $128 million and the Company recognized a gain on sale of $31 million on the Consolidated Statements of Earnings (Loss). In addition, as part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated which resulted in a gain of $2 million.

Other Held for Sale Assets

In December 2021, the Company transferred certain gas generation assets of $25 million to assets held for sale. On Nov. 7, 2022, the Company closed the sale of the gas generation assets, received net cash proceeds of $45 million and recognized a gain on sale of $20 million on the Consolidated Statements of Earnings (Loss).

In 2022, the Company transferred two Hydro assets to assets held for sale upon entering into a purchase and sale agreement. On Dec. 2, 2022, the Company closed the sale of these assets for the aggregate sale price and net cash proceeds of $6 million and recognized a gain on sale of $2 million on the Consolidated Statements of Earnings (Loss).

During 2022, the Company transferred $22 million to assets held for sale for cogeneration equipment.

During the fourth quarter of 2022, the Company recorded a contract settlement that was included in gain on sale of assets and other on the Consolidated Statements of Earnings (Loss).

19. Property, Plant and Equipment

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

	Assets under construction	Land	Hydro[1]	Wind and Solar[1]	Gas generation	Energy Transition	Capital spares and other[2]	Total
Cost								
As at Dec. 31, 2020	495	96	846	2,746	3,935	4,901	379	13,398
Additions[3]	477	—	—	—	—	—	2	479
Additions from development projects	1	—	—	—	—	—	—	1
Acquisitions (Note 4)	—	—	—	146	—	—	—	146
Disposals	(2)	(1)	—	—	(2)	(74)	—	(79)
Impairment charges (Note 7)[4]	(91)	—	(3)	(12)	(2)	(468)	(13)	(589)
Revisions/additions to decommissioning and restoration costs (Note 24)	—	—	1	128	6	—	—	135
Retirement of assets	—	—	(4)	(11)	(57)	(49)	—	(121)
Change in foreign exchange rates	—	—	—	3	(25)	2	(7)	(27)
Transfers (to) from assets held for sale (Note 18)	(25)	—	—	—	—	31	—	6
Transfers in (out) of PP&E[5]	5	—	—	(4)	(5)	46	—	42
Transfer of assets upon commissioning	(676)	1	27	280	237	124	5	(2)
As at Dec. 31, 2021	184	96	867	3,276	4,087	4,513	366	13,389
Additions [3]	**891**	**—**	**—**	**—**	**—**	**—**	**6**	**897**
Additions from development projects	**17**	**—**	**—**	**—**	**—**	**—**	**12**	**29**
Disposals	**—**	**(3)**	**—**	**—**	**(1)**	**(216)**	**—**	**(220)**
Impairment (charges) reversals (Note 7)[4]	**2**	**—**	**(21)**	**(43)**	**—**	**—**	**—**	**(62)**
Revisions/additions to decommissioning and restoration costs (Note 24)	**—**	**—**	**(15)**	**(59)**	**(12)**	**10**	**2**	**(74)**
Retirement of assets	**—**	**—**	**(9)**	**(9)**	**(12)**	**(7)**	**(2)**	**(39)**
Change in foreign exchange rates	**13**	**—**	**—**	**45**	**(4)**	**97**	**2**	**153**
Transfers to assets held for sale (Note 18)	**(22)**	**—**	**(9)**	**—**	**—**	**—**	**—**	**(31)**
Transfers in (out) of PPE[5]	**16**	**—**	**—**	**(22)**	**437**	**(442)**	**(13)**	**(24)**
Transfer of assets upon commissioning	**(138)**	**—**	**27**	**45**	**35**	**19**	**6**	**(6)**
As at Dec. 31, 2022	**963**	**93**	**840**	**3,233**	**4,530**	**3,974**	**379**	**14,012**
Accumulated depreciation								
As at Dec. 31, 2020	—	—	447	969	2,058	3,933	169	7,576
Depreciation	—	—	24	130	184	264	12	614
Retirement of assets	—	—	(3)	(6)	(55)	(48)	—	(112)
Disposals	—	—	—	—	(1)	(72)	—	(73)
Change in foreign exchange rates	—	—	—	—	(8)	2	(1)	(7)
Transfers to assets held for sale (Note 18)	—	—	—	—	—	31	—	31
Transfers from right-of-use assets	—	—	—	—	—	40	—	40
As at Dec. 31, 2021	—	—	468	1,093	2,178	4,150	180	8,069
Depreciation	**—**	**—**	**21**	**130**	**308**	**63**	**16**	**538**
Retirement of assets	**—**	**—**	**(8)**	**(6)**	**(10)**	**(7)**	**(2)**	**(33)**
Disposals	**—**	**—**	**—**	**—**	**(1)**	**(211)**	**—**	**(212)**
Change in foreign exchange rates	**—**	**—**	**—**	**11**	**2**	**89**	**—**	**102**
Transfers to assets held for sale (Note 18)	**—**	**—**	**(3)**	**—**	**—**	**—**	**—**	**(3)**
Transfers in (out) of PP&E[5]	**—**	**—**	**—**	**—**	**335**	**(340)**	**—**	**(5)**
As at Dec. 31, 2022	**—**	**—**	**478**	**1,228**	**2,812**	**3,744**	**194**	**8,456**
Carrying amount								
As at Dec. 31, 2020	495	96	399	1,777	1,877	968	210	5,822
As at Dec. 31, 2021	184	96	399	2,183	1,909	363	186	5,320
As at Dec. 31, 2022	**963**	**93**	**362**	**2,005**	**1,718**	**230**	**185**	**5,556**

(1) The renewable generation that was previously disclosed has been separated by segment.
(2) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance.
(3) In 2022, the Company capitalized $16 million (2021 – $14 million) of interest to PP&E in at a weighted average rate of 6.0 per cent (2021 – 6.0 per cent).
(4) The 2021 impairment charges, net of reversals exclude the changes in decommissioning and restoration provisions on assets.
(5) Includes transfers between PP&E classifications, net of accumulated depreciation.

Assets under Construction

The Company commenced construction on the Horizon Hill wind project and White Rock wind projects in 2022. The Company also began its rehabilitation plan of the Kent Hills wind facilities during the second quarter of 2022 and capitalized additions of $77 million in 2022. Initial construction activities on the Garden Plain wind project started in the third quarter of 2021 and the Northern Goldfields Solar project in the fourth quarter of 2021, with construction activities continuing throughout 2022 for both projects.

Change in Estimate - Useful Lives

During 2022, the Company adjusted the useful lives of certain assets included in the Gas segment to reflect changes made based on the future operating expectations of the assets. This resulted in an increase of $132 million in depreciation expense that was recognized in the Consolidated Statement of Earnings (Loss) in 2022.

20. Right-of-Use Assets

The Company 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
As at Dec. 31, 2020	58	24	1	16	42	141
Additions	—	1	—	—	—	1
Acquisitions (Note 4)	13	—	—	—	—	13
Depreciation	(3)	(5)	—	(2)	(1)	(11)
Disposal of assets	—	—	—	—	(41)	(41)
Transfers	—	—	—	(8)	—	(8)
As at Dec. 31, 2021	68	20	1	6	—	95
Additions	**36**	**—**	**1**	**3**	**—**	**40**
Depreciation	**(4)**	**(5)**	**—**	**(2)**	**—**	**(11)**
Change in foreign exchange rates	**2**	**—**	**—**	**—**	**—**	**2**
As at Dec. 31, 2022	**102**	**15**	**2**	**7**	**—**	**126**

During 2022, the Company recognized additions of $36 million mainly related to land leases for the Horizon Hill and White Rock wind projects.

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO. As part of the transaction, the natural gas transportation agreement with the Pioneer Pipeline Limited Partnership was terminated, which resulted in the derecognition of the right-of-use asset of $41 million and lease liability of $43 million related to the pipeline, resulting in a gain of $2 million.

For the year ended Dec. 31, 2022, TransAlta paid $16 million (2021 – $15 million) related to recognized lease liabilities, consisting of $9 million (2021 – $8 million) of principal repayments and $7 million (2021 – $7 million) of interest expense.

Short-term leases (term of less than 12 months) and leases with total lease payments below the Company's capitalization threshold (low value leases) do not require recognition as lease liabilities and right-of-use assets. For the year ended Dec. 31, 2022, the Company expensed $2 million (2021 and 2020 – nil) related to short-term and low value leases.

Some of the Company'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, 2022, the Company expensed $8 million (2021 – $6 million and 2020 – $7 million) in variable land lease payments for these leases.

21. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale contracts	Software and other	Intangibles under development	Coal rights	Total
Cost					
As at Dec. 31, 2020	269	412	3	149	833
Additions	—	—	9	—	9
Impairment charges (Note 7)	—	—	—	(17)	(17)
Change in foreign exchange rates	—	(2)	—	—	(2)
Transfers	—	12	(8)	—	4
As at Dec. 31, 2021	269	422	4	132	827
Additions[(1)]	**—**	**—**	**31**	**—**	**31**
Change in foreign exchange rates	**3**	**3**	**1**	**—**	**7**
Transfers	**—**	**12**	**(9)**	**—**	**3**
As at Dec. 31, 2022	**272**	**437**	**27**	**132**	**868**
Accumulated amortization					
As at Dec. 31, 2020	123	272	—	125	520
Amortization	17	27	—	7	51
As at Dec. 31, 2021	140	299	—	132	571
Amortization	**17**	**26**	**—**	**—**	**43**
Change in foreign exchange rates	**1**	**1**	**—**	**—**	**2**
As at Dec. 31, 2022	**158**	**326**	**—**	**132**	**616**
Carrying amount					
As at Dec. 31, 2020	146	140	3	24	313
As at Dec. 31, 2021	129	123	4	—	256
As at Dec. 31, 2022	**114**	**111**	**27**	**—**	**252**

(1) In 2022, the Company reclassified $19 million in project development costs related to various US Wind projects to intangible assets. Refer to Note 23 for further details. Other additions relate to corporate software costs.

22. Goodwill

Goodwill acquired through business combinations has been allocated to groups of CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments is as follows:

As at Dec. 31	2022	2021
Hydro	**258**	258
Wind and Solar	**176**	175
Energy Marketing	**30**	30
Total goodwill	**464**	463

For the purposes of the 2022 goodwill impairment review, the Company determined the recoverable amounts of the Hydro, Wind and Solar and Energy Marketing segments by calculating the fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts for the period extending to the last planned asset retirement in 2072. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment.

The key assumptions impacting the determination of fair value for the Hydro, Wind and Solar and Energy Marketing segments are the following:

- Discount rates used for the goodwill impairment calculation in 2022 for the Hydro, Wind and Solar, and Energy Marketing segments ranged from 5.9 per cent to 8.2 per cent (2021 – 5.0 per cent to 6.4 per cent).
- 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. Merchant electricity prices used in these 2022 models ranged between $28 to $233 per MWh during the forecast period (2021 – $17 to $136 per MWh).

23. Other Assets

The components of other assets are as follows:

As at Dec. 31	2022	2021
Loan receivable	**37**	55
South Hedland prepaid transmission access and distribution costs	**61**	65
Long-term prepaids and other assets	**56**	48
Project development costs	**10**	29
Total Other assets	**164**	197
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 13)	**4**	55
Total long-term other assets	**160**	142
Total Other assets	**164**	197

The loan receivable of $37 million (2021 – $55 million) is an unsecured loan related to an advancement by the Company's subsidiary, Kent Hills Wind LP, of the net financing proceeds of the Kent Hills Wind Bond ("KH Bonds"), to its 17 per cent partner. On June 1, 2022, the loan receivable agreement was amended and its original maturity date of Oct. 2, 2022, was extended to October 2027, resulting in the classification of a portion of the loan receivable to non-current assets. The remaining terms of the original loan are unchanged and it continues to bear interest at 4.55 per cent, with interest payable quarterly. No scheduled principal repayments are required until maturity. However, repayments may be required for amounts associated with foundation replacement capital expenditures and for operating account funding, as outlined in the amendment made to the KH Bonds. During 2022, the Company received repayments of $18 million that were required as part of the waiver and amendment made to the KH Bonds.

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.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 37 (G), costs related to transmission infrastructure and other contractually required prepayments and deposits. During 2022, $16 million of costs related to transmission infrastructure at the Windrise wind facility were reclassified from PP&E to other assets (long-term prepaids and other assets) and will be amortized to net earnings (loss) over the useful life of the Windrise wind facility.

Project development costs primarily include the pre-construction project costs for projects. The change in project development costs is as follows:

As at Dec. 31	2022	2021
Balance, Jan 1	**29**	25
Additions	**29**	15
Transfers to PP&E (Note 19)	**(29)**	(1)
Transfers to intangible assets (Note 21)	**(19)**	—
Impairment charges (Note 7)	**—**	(10)
Balance, Dec. 31	**10**	29

24. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2020	608	65	673
Liabilities incurred	8	22	30
Liabilities settled	(18)	(62)	(80)
Accretion	32	—	32
Acquisition of liabilities	2	—	2
Revisions in estimated cash flows	167	12	179
Revisions in discount rates	(6)	—	(6)
Reversals	—	(3)	(3)
Balance, Dec. 31, 2021	793	34	827
Liabilities incurred	**1**	**23**	**24**
Liabilities settled	**(35)**	**(12)**	**(47)**
Accretion (Note 10)	**49**	**—**	**49**
Disposals	**(5)**	**—**	**(5)**
Revisions in estimated cash flows	**95**	**5**	**100**
Revisions in discount rates	**(225)**	**—**	**(225)**
Reversals	**—**	**(9)**	**(9)**
Change in foreign exchange rates	**15**	**—**	**15**
Balance, Dec. 31, 2022	**688**	**41**	**729**

Included in the Consolidated Statements of Financial Position as:		
As at Dec. 31,	**2022**	2021
Current portion	**70**	48
Non-current portion	**659**	779
Total Decommissioning and other provisions	**729**	827

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 $1.6 billion, which will be incurred between 2023 and 2072. The majority of the costs will be incurred between 2023 and 2050.

During 2022, the Company accelerated the expected timing on decommissioning and restoration for certain facilities. This increased the decommissioning and restoration provision by $95 million, of which $46 million increased operating assets in PP&E and $49 million was recognized as an impairment charge in net earnings related to retired assets.

In 2021, the Company increased the decommissioning and restoration provision by $167 million related to an engineering study on the decommissioning costs of the wind sites of $120 million and the Sundance and Keephills Units change in useful lives of $47 million. Of the total increase in decommissioning and restoration provisions,$133 million increased operating assets in PP&E and $34 million was recognized as an impairment charge in net earnings related to retired assets.

During 2022, the decommissioning and restoration provision decreased by $225 million (2021 – $6 million) due to a significant increase in discount rates, largely driven by increases in market benchmark rates. On average, discount rates increased with rates ranging from 7.0 to 9.7 per cent as at Dec. 31, 2022 (2021 – 3.6 to 6.5 per cent). This has resulted in a corresponding decrease in PP&E of $123 million (2021 – $6 million) on operating assets and recognition of a $102 million (2021 – nil) impairment reversal in net earnings related to retired assets.

At Dec. 31, 2022, the Company has provided a surety bond in the amount of US$147 million (2021 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2022, the Company had provided a surety bond and letters of credit in the amount of $187 million (2021 – $188 million) in support of future decommissioning obligations at the Highvale mine.

B. Other Provisions

Other provisions include provisions arising from ongoing business activities, amounts related to commercial disputes between the Company and customers or suppliers and onerous contract provisions. 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 Company's ability to settle the provisions in the most favourable manner.

The onerous contract provisions occurred as a result of decisions to no longer operate on coal in Canada. Future royalty payments related to the extraction of coal at the Highvale mine will occur until 2023 under the royalty contract. Payments related to coal contracts for Sheerness are required until 2025. At Dec. 31, 2022, the remaining balance of the provision for the onerous royalty contract was $7 million and the remaining balance of the onerous coal contract was $10 million.

25. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31				2022			2021		
	Segment	Maturity	Currency	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility[2]	Corporate	2026	CAD	**32**	**33**	**4.7%**	—	—	—%
Term Facility	Corporate	2024	CAD	**396**	**400**	**6.5%**	—	—	—%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	**110**	**110**	**7.3%**	110	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	**141**	**141**	**6.9%**	141	141	6.9%
Senior notes[3]									
7.8% Senior notes[4]	Corporate	2029	USD	**533**	**542**	**7.8%**	—	—	—%
6.5% Senior notes	Corporate	2040	USD	**401**	**407**	**6.5%**	378	383	6.5%
4.5% Senior notes	Corporate	2022	USD	—	—	**4.5%**	510	511	4.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	**202**	**203**	**3.8%**	235	237	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	**112**	**113**	**4.0%**	120	121	4.0%
Kent Hills Wind LP bond	Wind & Solar	2033	CAD	**206**	**209**	**4.5%**	221	221	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	**170**	**173**	**3.4%**	171	173	3.4%
Pingston bond	Hydro	2023	CAD	**45**	**45**	**3.0%**	45	45	3.0%
TAPC Holdings LP bond (Poplar Creek)	Gas	2030	CAD	**94**	**95**	**8.9%**	102	104	4.4%
TEC Hedland PTY Ltd bond[5]	Gas	2042	AUD	**711**	**720**	**4.1%**	732	742	4.1%
TransAlta OCP LP bond	Gas	2030	CAD	**241**	**242**	**4.5%**	263	265	4.5%
Tax equity financing									
Big Level & Antrim[6]	Wind & Solar	2029	USD	**102**	**108**	**6.6%**	106	112	6.6%
Lakeswind[7]	Wind & Solar	2024	USD	**15**	**15**	**10.5%**	18	18	10.5%
North Carolina Solar[8]	Wind & Solar	2028	USD	**6**	**6**	**7.3%**	11	11	7.3 %
Other	Corporate	2023	CAD	**1**	**1**	**5.9%**	4	4	5.9%
Total long-term debt				**3,518**	**3,563**		3,167	3,198	
Lease liabilities				**135**			100		
Total long-term debt and lease liabilities				**3,653**			3,267		
Less: current portion of long-term debt				**(170)**			(837)		
Less: current portion of lease liabilities				**(8)**			(7)		
Total current long-term debt and lease liabilities				**(178)**			(844)		
Total non-current credit facilities, long-term debt and lease liabilities				**3,475**			2,423		

(1) Interest rate reflects the stipulated rate or the average rate weighted by principal amounts outstanding and is 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, 2022 — US$700 million (2021 – US$700 million).
(4) The effective interest rate for the senior notes is 5.98 per cent after the effects of gains realized on settled interest rate hedging instruments.
(5) AU face value at Dec. 31, 2022 — AU$786 million (2021 – AU$800 million).
(6) US face value at Dec. 31, 2022 — US$79 million (2021 – US$88 million).
(7) US face value at Dec. 31, 2022 — US$11 million (2021 – US$14 million).
(8) US face value at Dec. 31, 2022 — US$5 million (2021 – US$9 million).

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

As at Dec. 31, 2022		Utilized			
Credit Facilities	Facility size	Outstanding letters of credit[(1)]	Cash drawings	Available capacity	Maturity date
Committed					
TransAlta Corporation syndicated credit facility	1,250	738	—	512	Q2 2026
TransAlta Renewables syndicated credit facility	700	—	33	667	Q2 2026
TransAlta Corporation bilateral credit facilities	240	219	—	21	Q2 2024
TransAlta Corporation Term Facility	400	—	400	—	Q3 2024
Total Committed	**2,590**	**957**	**433**	**1,200**	
Non-Committed					
TransAlta Corporation demand facilities	250	120	—	130	n/a
TransAlta Renewables demand facility	150	98	—	52	n/a
Total Non-Committed	**400**	**218**	**—**	**182**	

(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. Letters of credit drawn against the non-committed facilities reduce the available capacity under the committed syndicated credit facilities. At Dec. 31, 2022, TransAlta provided cash collateral of $304 million.

These facilities are the primary source for short-term liquidity after the cash flow generated from the Company's business. The TransAlta Corporation committed syndicated credit facility was converted into a Sustainability Linked Loan in 2021.

During 2022, the Company closed a two-year $400 million floating rate Term Facility with its banking syndicate maturing on Sept. 7, 2024. In addition, the committed syndicated credit facilities were extended by one year to June 30, 2026 and the committed bilateral credit facilities were extended by one year to June 30, 2024. Interest rates on the credit facilities and Term Facility vary depending on the option selected (Canadian prime, bankers' acceptances, SOFR or US base rate, etc.) in accordance with a pricing grid that is standard for such facilities.

The Company is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.0 billion available under the credit facilities, the Company also has $1.1 billion of available cash and cash equivalents, net of bank overdraft, and $17 million ($17 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

TransAlta has letters of credit of $218 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

Senior Notes

On Nov. 17, 2022, the Company issued US$400 million senior notes ("US$400 million Senior Green Bonds"), which have a fixed coupon rate of 7.75 per cent per annum and matures on Nov. 15, 2029. Including the effects of settled interest rate swaps, the notes have an effective yield of approximately 5.982 per cent. The notes are unsecured and rank equally in right of payment with all of our existing and future senior indebtedness and senior in right of payment to all of our future subordinated indebtedness. The interest payments on the bonds are made semi-annually, on November 15 and May 15 with the first payment commencing May 15, 2023. TransAlta will allocate an amount equal to the net proceeds from this offering to finance or refinance, new and/or existing eligible green projects in accordance with its Green Bond Framework ("the Framework"). The Framework received a second-party opinion from Sustainalytics, which verified that it aligned with the Green Bond Principles from the International Capital Markets Association.

On Nov. 15, 2022, the Company repaid the US$400 million 4.50 per cent unsecured senior notes on its maturity in addition to related fees and expenses.

A total of US$370 million (2021 – US$370 million) of the senior notes has been designated as a hedge of the Company’s net investment in US operations.

Non-Recourse Debt

On Dec. 6, 2021, TransAlta completed a secured green bond by way of private placement for approximately $173 million ("Windrise Wind LP Bond Offering"). Windrise Wind LP Bond Offering is secured by a first ranking charge over all assets of the issuer, Windrise Wind LP and the bonds amortize and bear interest from their date of issue at a rate of 3.41 per cent per annum and mature on Sept. 30, 2041. Payments on the bonds will be interest-only to and including Dec. 31, 2022, with quarterly blended payments of principal and interest commencing on March 31, 2023. TransAlta used the proceeds of the Windrise Wind LP Bond Offering to finance or refinance eligible green projects, including renewable energy facilities and to fund a construction reserve account.

Tax Equity

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 and North Carolina Solar acquired tax equity financings, which were initially recognized at their fair values. Tax equity financing balances are reduced by the value of tax benefits (production tax credits, tax depreciation and investment tax credits) 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. The maturity dates of each financing are subject to change and are primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Company anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim in December 2029; Lakeswind in March 2024 and North Carolina Solar in December 2028.

Other

Other debt 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.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2022, the Company was in compliance with all debt covenants.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston Power Inc., TAPC Holdings LP, New Richmond Wind LP, Kent Hills Wind LP, TEC Hedland Pty Ltd notes, Windrise Wind LP and TransAlta OCP LP non-recourse bonds with a carrying value of $1.8 billion as at Dec. 31, 2022 (2021 – $1.9 billion) are subject to customary financing conditions and covenants that may restrict the Company's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter of 2022 with the exception of Kent Hills Wind LP, as discussed below and TAPC Holdings LP, which has been impacted by higher interest rates in 2022. The funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2023. At Dec. 31, 2022, $50 million (2021 – $67 million) of cash was subject to these financial restrictions.

Proceeds received from the TEC Hedland Pty Ltd notes in the amount of $8 million (AU$9 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.

Kent Hills Wind Bonds

In the fourth quarter of 2021, the Company disclosed that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Accordingly, the Company classified the entire carrying value of the bonds as current as at Dec. 31, 2021.

During the second quarter of 2022, the Company obtained a waiver and entered into a supplemental indenture that facilitated the rehabilitation of the Kent Hills 1 and 2 wind facilities. Upon receipt of the waiver, the Company reclassified a portion of the carrying value outstanding for the KH Bonds to non-current liabilities with the exception of the scheduled principal repayments due within the next 12 months. In accordance with the supplemental indenture, Kent Hills Wind LP cannot make any distributions to its partners until the foundation replacement work has been completed.

A foundation replacement reserve account was set up in accordance with the supplemental indenture, with funds in the account being used to pay foundation replacement costs. The account is funded quarterly with the last funding requirement on April 1, 2023. The balance in the account is $65 million as at Dec. 31, 2022 (nil – Dec. 31, 2021).

C. Security

Non-recourse debts totalling $1.4 billion as at Dec. 31, 2022 (2021 – $1.5 billion) are each secured by a first ranking charge over all of the respective assets of the Company's subsidiaries that issued the bonds, which include PP&E with total carrying amounts of $1.5 billion at Dec. 31, 2022 (2021 – $1.5 billion) and intangible assets with total carrying amounts of $70 million (2021 – $78 million). At Dec. 31, 2022, a non-recourse bond of approximately $94 million (2021 – $103 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 $241 million (2021 – $263 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 Company receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Company), commencing on Jan. 1, 2017 and terminating at the end of 2030.

D. Principal Repayments

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Principal repayments(1)	170	527	142	177	154	2,393	**3,563**
Lease liabilities(2)	(7)	4	4	3	4	127	**135**

(1) Excludes impact of hedge accounting and derivatives.
(2) Lease liabilities include a lease incentive of $12 million, expected to be received in 2023.

E. Restricted Cash

The Company had $17 million (2021 – $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 scheduled future debt repayments.

The Company also had $53 million (2021 – $53 million) of restricted cash related to the TEC Hedland Pty Ltd bond; reserves are required to be held under 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 $1.3 billion committed syndicated credit facility, its $240 million bilateral committed credit facilities and its $250 million uncommitted demand facilities. TransAlta has drawn $738 million on its committed syndicated credit facility, $219 million on its bilateral committed credit facilities and $120 million on its uncommitted demand facilities.

Letters of credit issued by TransAlta Renewables are drawn on its $700 million committed syndicated credit facility and its $150 million uncommitted demand facility. TransAlta Renewables has drawn letters of credit of $98 million on its uncommitted demand facility.

Letters of credit are issued to counterparties under various contractual arrangements with the Company and certain subsidiaries of the Company. If the Company 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 Company 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, 2022, was $1,175 million (2021 – $902 million) with no (2021 – nil) amounts exercised by third parties under these arrangements.

G. Currency Impacts

The strengthening of the US dollar has increased the US-denominated long-term debt balances, mainly the senior notes and tax equity financing, by $41 million as at Dec. 31, 2022 (2021 – $1 million). Almost all of the US-denominated debt is hedged either through financial contracts or net investments in the US operations.

Additionally, the weakening of the Australian dollar has decreased the Australian-denominated non-recourse senior secured notes balance by approximately $9 million as at Dec. 31, 2022 (2021 – $40 million). As this debt is issued by an Australian subsidiary, the foreign currency translation impacts are recognized within other comprehensive income (loss).

26. Exchangeable Securities

On March 22, 2019, the Company entered into an Investment Agreement whereby Brookfield Renewable Partners or its affiliates (collectively "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").

A. $750 Million Exchangeable Securities

As at	Dec. 31, 2022			Dec. 31, 2021		
	Carrying value	**Face value**	**Interest**	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039[1]	**339**	**350**	**7%**	335	350	7%
Exchangeable preferred shares[2]	**400**	**400**	**7%**	400	400	7%
Total exchangeable securities	**739**	**750**		735	750	

(1) 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.
(2) On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in exchange for redeemable, retractable first preferred shares (Series 1). Exchangeable preferred share dividends are reported as interest expense.

On Dec. 12, 2022, the Company declared a dividend of $7 million in aggregate for Exchangeable Preferred Shares at the fixed rate of 1.764 per cent, per share, payable on Feb. 28, 2023. The Exchangeable Preferred Shares are considered debt for accounting purposes and as such, dividends are reported as interest expense (Note 10).

B. Option to Exchange

As at	Dec. 31, 2022		Dec. 31, 2021	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Option to exchange – embedded derivative	**—**	**+nil -25**	—	+nil -32

The Investment Agreement allows Brookfield the option to exchange all of the outstanding exchangeable securities after Dec. 31, 2024, into an equity ownership interest of up to a maximum 49 per cent in an entity that has been formed to hold TransAlta's Alberta Hydro Assets. 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 Company'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 per cent equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

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 Dec. 31, 2022, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,456,023 common shares, representing approximately 13.2 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.

27. 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	2022	2021
Defined benefit obligation (Note 32)	**150**	228
Long-term incentive accruals (Note 31)	**8**	4
Retail power contract liability	**126**	—
Other	**10**	21
Total	**294**	253

The liability for pension and post-employment benefits and associated costs included in compensation expenses are impacted by estimates related to changes in key actuarial assumptions, including discount rates. The defined benefit obligation has decreased by $78 million to $150 million as at Dec. 31, 2022, from $228 million as at Dec. 31, 2021. The decrease is primarily driven by increases in discount rates in 2022, largely driven by increases in market benchmark rates and the voluntary contribution of $35 million made to the Sunhills Mining Ltd. Pension Plan, partially offset by a decrease in plan assets due to poor market returns.

The Company made a voluntary contribution of $35 million during 2022 to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale mine and to support the employees affected by the closure of the Highvale mine in 2021 and our transition off-coal to cleaner sources. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

A 1 per cent increase in discount rates would result in a $39 million decrease in the defined benefit obligation. Refer to Note 32 for additional sensitivities impacting the defined benefit obligation.

On Dec. 1, 2022, the Company closed a purchase and sale agreement for customer retail contracts to deliver power and gas, along with power and gas financial swaps. The Company concluded this will be accounted for as an asset acquisition and allocated values to risk management assets of $139 million (level II valuation) and retail power contract liabilities of $129 million within the Gas segment. The retail power contract liabilities acquired represent certain off-market retail power customer contracts for which fair value was determined as the present value of the amount by which contract terms deviated from the terms that a market participant could have achieved at the closing date. The retail contract liability is amortized to other operating income over the remaining term of the contracts based on volumes that will be delivered each month.

28. 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	2022		2021	
	Common shares (millions)	**Amount**	Common shares (millions)	Amount
Issued and outstanding, beginning of year	**271.0**	**2,901**	269.8	2,896
Purchased and cancelled under the NCIB	**(4.3)**	**(46)**	—	—
Effects of share-based payment plans	**0.9**	**5**	—	(3)
Stock options exercised	**0.5**	**3**	1.2	8
Issued and outstanding, end of year	**268.1**	**2,863**	271.0	2,901

B. Normal Course Issuer Bid ("NCIB") Program

Shares purchased by the Company 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 Company's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31	2022	2021
Total shares purchased[1]	4,342,300	—
Average purchase price per share	12.48	—
Total cost (millions)	54	—
Weighted average book value of shares cancelled	46	—
Amount recorded in deficit	(8)	—

(1) As at Dec. 31, 2022, includes 164,300 (2021 – nil) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date. The Company paid $52 million in 2022 and the remaining amount was paid subsequent to the year end.

2022

On May 24, 2022, the Toronto Stock Exchange (“TSX”) accepted the notice filed by the Company to renew its normal course issuer bid for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14 million common shares, representing approximately 7.16 per cent of its public float of common shares as at May 17, 2022. Any common shares purchased under the NCIB are cancelled. The period during which TransAlta is authorized to make purchases under the NCIB commenced on May 31, 2022, and ends on May 30, 2023.

2021

On May 25, 2021, the Company announced that the TSX accepted the notice filed by the Company to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, TransAlta may repurchase up to a maximum of 14 million common shares, representing approximately 7.16 per cent of its public float of common shares as at May 18, 2021. No common shares were repurchased in 2021 under the current and previous NCIB.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 28, 2022. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 28, 2022, and will need to be approved at the annual meeting of shareholders in 2025. 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 Company'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	2022	2021	2020
Net earnings (loss) attributable to common shareholders	**4**	(576)	(336)
Basic and diluted weighted average number of common shares outstanding (millions)	**271**	271	275
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**0.01**	(2.13)	(1.22)

E. Dividends

On Dec. 12, 2022, the Company declared a quarterly dividend of $0.055 per common share, payable on April 1, 2023.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

29. 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	2022		2021	
Series(1)	Number of shares (millions)	Amount	Number of shares (millions)	Amount
Series A	**9.6**	**235**	9.6	235
Series B	**2.4**	**58**	2.4	58
Series C	**10.0**	**243**	11.0	269
Series D	**1.0**	**26**	—	—
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

(1) Series 1 Preferred Shares are accounted for as long-term debt. Refer to Note 26.

I. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On March 31, 2021, the Company converted 1,417,338 of its 10.2 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") and 871,871 of its 1.8 million Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares"), on a one-for-one basis, into Series B Shares and Series A Shares.

II. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 30, 2022, the Company converted 1,044,299 of its 11.0 million Cumulative Redeemable Rate Reset First Preferred Shares, Series C ("Series C Shares"), on a one-for-one basis, into Cumulative Redeemable Floating Rate First Preferred Shares, Series D ("Series D Shares").

The Series C Shares will pay fixed cumulative preferential cash dividends on a quarterly basis, for the five-year period from and including June 30, 2022, to but excluding June 30, 2027, if, as and when declared by the Board. The annual fixed dividend rate of 5.854 per cent, being equal to the five-year Government of Canada bond yield of 2.754 per cent determined as of May 31, 2022, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

The Series D Shares will pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including June 30, 2022, to but excluding June 30, 2027, if, as and when declared by the Board. The quarterly dividend rate for the Series D Shares will be established each quarter, being equal to the annual rate for the auction of 90-day Government of Canada Treasury Bills, plus 3.10 per cent, in accordance with the terms of the Series D Shares.

III. Series E Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On Sept. 21, 2022, the Company announced that, after taking into account all election notices received 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 89,945 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.

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, 2022, to but excluding Sept. 30, 2027, will be 6.894 per cent, which is equal to the five-year Government of Canada bond yield of 3.244 per cent, determined as of Aug. 31, 2022, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at specified rates, 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 Company, 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 Company 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, 2022, are as follows:

Series	Rate during term	Annual dividend rate per share ($)(1)	Next conversion date	Rate spread over benchmark (per cent)	Convertible to Series
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	1.10295	March 31, 2026	2.03	A
C	Fixed	1.34933	Jun. 30, 2027	3.10	D
D	Floating	1.40030	Jun. 30, 2027	3.10	C
E	Fixed	1.51102	Sept. 30, 2027	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.24700	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

(1) The annual dividend rate per share represents dividends declared in 2022.

B. Dividends

The following table summarizes the value of the preferred share dividends declared in 2022 and 2021:

Series	Total dividends declared	
	2022(1)	2021(1)
A	**7**	7
B(2)	**3**	1
C	**14**	11
D(3)	**1**	—
E	**13**	12
G	**8**	8
Total for the year	**46**	39

(1) No dividends were declared in the first quarter of the year as the quarterly dividend related to the period covering the first quarter was declared in December of the prior year.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.0 per cent.
(3) Series D Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 3.1 per cent.

On Dec. 12, 2022, the Company declared a quarterly dividend of $0.17981 per share on the Series A preferred shares, $0.37991 per share on the Series B preferred shares, $0.36588 per share on the Series C preferred shares, $0.45578 per share on the Series D preferred shares, $0.43088 per share on the Series E preferred shares and $0.31175 per share on the Series G preferred shares, all payable on March 31, 2023.

30. Accumulated Other Comprehensive Income (Loss)

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

	2022	2021
Currency translation adjustment		
Opening balance, Jan. 1	**(35)**	(21)
Losses (gains) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**21**	(14)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(1)	**(25)**	—
Balance, Dec. 31	**(39)**	(35)
Cash flow hedges		
Opening balance, Jan. 1	**228**	436
Losses on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(2)	**(456)**	(208)
Balance, Dec. 31	**(228)**	228
Employee future benefits		
Opening balance, Jan. 1	**(29)**	(66)
Net actuarial gains on defined benefit plans, net of tax(3)	**37**	37
Balance, Dec. 31	**8**	(29)
Other		
Opening balance, Jan. 1	**(18)**	(47)
Intercompany and third-party investments at FVTOCI	**55**	29
Balance, Dec. 31	**37**	(18)
Accumulated other comprehensive income (loss)	**(222)**	146

(1) Net of income tax recovery of $3 million for the year ended Dec. 31, 2022 (2021 – nil).
(2) Net of income tax recovery of $112 million for the year ended Dec. 31, 2022 (2021 – $57 million).
(3) Net of income tax expense of $12 million for the year ended Dec. 31, 2022 (2021 – $11 million).

31. Share-Based Payment Plans

The Company has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the Share Unit Plan, grants of PSUs and RSUs 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 Company's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of specific 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 Company's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Company's common shares.

The pre-tax compensation expense related to PSUs and RSUs in 2022 was $20 million (2021 – $14 million, 2020 – $15 million), which is included in OM&A in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the Share Unit 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 Company and fluctuates based on the changes in the value of the Company's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Company'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 Company.

The Company 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 DSU's was nil in 2022 (2021 – $3 million expense, 2020 – $1 million expense).

C. Stock Option Plan

In 2022, the Company granted executive officers of the Company a total of 0.3 million stock options with a weighted average exercise price of $12.66 that vest over a three-year period and expire 7 years after issuance (2021 – 0.7 million stock options at $9.86; 2020 – 0.7 million stock options at $9.17). The expense recognized relating to these grants during 2022 was approximately $1 million (2021 – approximately $2 million, 2020 – approximately $2 million).

The total options outstanding and exercisable under the Stock Option Plan at Dec. 31, 2022, 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)
5.00-12.00	**3.0**	**3.89**	**8.41**

(1) Options currently exercisable as at Dec. 31, 2022.

On May 24, 2021, the Company's shareholders approved amendments to the Stock Option Plan to reduce the total aggregate number of common shares held in reserve for issuance under this program. The amendments reduce the aggregate total number of shares reserved for issuance to 14.5 million common shares as at March 31, 2021. The Company is authorized to grant options to purchase up to an aggregate of 14.5 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The number of common shares that may be (i) issued to insiders within any one-year period, or (ii) issuable to insiders at any time, in each case, under the Stock Option Plan alone or when combined with all other security-based compensation arrangements (including the Share Unit Plan), shall not exceed 10 per cent of the total number of common shares issued and outstanding from time to time. The Stock Option Plan provides for grants of options to eligible employees, including executives, designated by the Human Resources Committee from time to time.

32. Employee Future Benefits

A. Description

The Company sponsors registered pension plans in Canada and the US covering substantially all employees of the Company 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, 2022. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2021. 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, 2022.

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 Company. The Company 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 Company posted a letter of credit in March 2022 in the amount of $96 million to secure the obligations under the supplemental plan.

The Company 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, 2021 and Jan. 1, 2022, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2022.

The Company 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 11 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, 2022	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**1**	**1**	**—**	**2**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**13**	**3**	**—**	**16**
Interest on plan assets	**(9)**	**—**	**—**	**(9)**
Defined benefit expense	**6**	**4**	**—**	**10**
Defined contribution expense	**11**	**—**	**—**	**11**
Net expense	**17**	**4**	**—**	**21**

Year ended Dec. 31, 2021	Registered	Supplemental	Other	Total
Current service cost	3	2	1	6
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	12	2	—	14
Interest on plan assets	(8)	—	—	(8)
Curtailment and amendment gain	(7)	—	—	(7)
Defined benefit expense	1	4	1	6
Defined contribution expense	8	—	—	8
Net expense	9	4	1	14

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

C. Status of Plans

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

Year ended Dec. 31, 2022	Registered	Supplemental	Other	Total
Fair value of plan assets	**274**	**15**	**—**	**289**
Present value of defined benefit obligation	**(345)**	**(85)**	**(17)**	**(447)**
Funded status – plan deficit	**(71)**	**(70)**	**(17)**	**(158)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(1)**	**(6)**	**(1)**	**(8)**
Other long-term liabilities	**(70)**	**(64)**	**(16)**	**(150)**
Total amount recognized	**(71)**	**(70)**	**(17)**	**(158)**

Year ended Dec. 31, 2021	Registered	Supplemental	Other	Total
Fair value of plan assets	339	14	—	353
Present value of defined benefit obligation	(469)	(101)	(23)	(593)
Funded status – plan deficit	(130)	(87)	(23)	(240)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(4)	(6)	(2)	(12)
Other long-term liabilities	(126)	(81)	(21)	(228)
Total amount recognized	(130)	(87)	(23)	(240)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
As at Dec. 31, 2020	367	14	—	381
Interest on plan assets	8	—	—	8
Net return (loss) on plan assets	14	(1)	—	13
Contributions	5	6	1	12
Benefits paid	(54)	(5)	(1)	(60)
Administration expenses	(1)	—	—	(1)
As at Dec. 31, 2021	339	14	—	353
Interest on plan assets	**9**	**—**	**—**	**9**
Net loss on plan assets	**(55)**	**—**	**—**	**(55)**
Contributions(1)	**38**	**6**	**—**	**44**
Benefits paid	**(57)**	**(5)**	**—**	**(62)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
Change in foreign exchange rates	**1**	**—**	**—**	**1**
As at Dec. 31, 2022	**274**	**15**	**—**	**289**

(1) The Company made a voluntary contribution of $35 million to further improve the funded status of the Sunhills Mining Ltd. Pension Plan for the Highvale mine. The contribution reduces the amount of the Company's future funding obligations, including amounts secured by the letters of credit.

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

As at Dec. 31, 2022	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	18	—	18
US	12	5	—	17
International	38	41	—	79
Private	—	—	1	1
Bonds				
AAA	—	24	—	24
AA	—	38	—	38
A	—	26	—	26
BBB	1	18	—	19
Below BBB	—	6	—	6
Loans				
A	—	1	—	1
BBB	—	1	—	1
Alternative funds(1)	—	—	39	39
Money market and cash and cash equivalents	—	20	—	20
Total	51	198	40	289

(1) Alternative funds include investments in infrastructure and real estate funds.

As at Dec. 31, 2021	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	29	4	33
US	—	20	—	20
International	47	79	—	126
Private	—	—	1	1
Bonds				
AAA	—	28	—	28
AA	—	54	—	54
A	—	36	—	36
BBB	1	24	—	25
Below BBB	—	10	—	10
Money market and cash and cash equivalents	—	20	—	20
Total	48	300	5	353

Plan assets do not include any common shares of the Company at Dec. 31, 2022 and Dec. 31, 2021.

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, 2020	542	109	24	675
Current service cost	3	2	1	6
Interest cost	12	2	—	14
Benefits paid	(54)	(5)	(1)	(60)
Curtailment	(7)	—	—	(7)
Actuarial gain arising from financial assumptions	(26)	(7)	(1)	(34)
Actuarial gain arising from experience adjustments	(1)	—	—	(1)
Present value of defined benefit obligation as at Dec. 31, 2021	469	101	23	593
Current service cost	**1**	**1**	**—**	**2**
Interest cost	**13**	**3**	**—**	**16**
Benefits paid	**(57)**	**(5)**	**1**	**(61)**
Actuarial gain arising from financial assumptions	**(83)**	**(22)**	**(5)**	**(110)**
Actuarial loss (gain) arising from experience adjustments	**1**	**7**	**(2)**	**6**
Change in foreign exchange rates	**1**	**—**	**—**	**1**
Present value of defined benefit obligation as at Dec. 31, 2022	**345**	**85**	**17**	**447**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2022, is 9.9 years.

F. Contributions

The expected employer contributions for 2023 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**1**	**6**	**2**	**9**

G. Assumptions

The significant actuarial assumptions used in measuring the Company's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	2022			2021		
As at Dec. 31 (per cent)	Registered	Supplemental	Other	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**4.7**	**5.0**	**5.0**	2.8	2.8	2.7
Rate of compensation increase	**2.6**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**7.1**	—	—	6.8
Dental-care cost escalation	**—**	**—**	**4.2**	—	—	4.0
Benefit cost for the year						
Discount rate	**2.8**	**2.8**	**2.7**	2.4	2.3	2.3
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**6.8**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.7**	—	—	4.0

(1) 2022 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2032 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
(2) 2022 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2031 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
(3) 2021 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 for Canada.
(4) 2021 Post- and pre-65 rates: decreasing gradually to 4.5 per cent by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3 per cent per year to 4.5 per cent in 2030 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, 2022	**Registered**	**Supplemental**	**Other**	**Pension**
1% decrease in the discount rate	**31**	**10**	**2**	**2**
1% increase in the salary scale	**1**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**1**	**—**
10% improvement in mortality rates	**12**	**2**	**—**	**1**

33. Joint Arrangements

Joint arrangements at Dec. 31, 2022, included the following:

Joint operations	Segment	Ownership (per cent)	Description
Sheerness	Gas	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
Goldfields Power	Gas	50	Gas-fired facility in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind 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 venture	Segment	Ownership (per cent)	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power

34. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2022**	2021	2020
(Use) source:			
Accounts receivable	**(869)**	(28)	(79)
Prepaid expenses	**—**	9	2
Income taxes receivable	**(61)**	—	(4)
Inventory	**6**	42	6
Accounts payable, accrued liabilities and provisions	**548**	153	160
Income taxes payable	**60**	(2)	4
Change in non-cash operating working capital	**(316)**	174	89

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2021	**Cash issuances(1)**	**Repayments and dividends paid(2)**	**New leases**	**Dividends declared**	**Foreign exchange impact**	**Other**	**Balance Dec. 31, 2022**
Long-term debt and lease liabilities	3,267	**981**	**(630)**	**40**	**—**	**39**	**(28)**	**3,669**
Exchangeable securities	735	**—**	**—**	**—**	**—**	**—**	**4**	**739**
Dividends payable (common and preferred)	62	**—**	**(97)**	**—**	**103**	**—**	**—**	**68**
Total liabilities from financing activities	4,064	**981**	**(727)**	**40**	**103**	**39**	**(24)**	**4,476**

(1) Includes $449 million net increase in borrowings under credit facilities and an increase in issuance of long-term debt of $532 million.
(2) Includes a decrease of $621 million related to the repayment of long-term debt and a decrease in finance lease obligations of $9 million.

	Balance Dec. 31, 2020	Cash issuances(1)	Repayments and dividends paid(2)	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2021
Long-term debt and lease liabilities	3,361	173	(214)	1	—	(39)	(15)	3,267
Exchangeable securities	730	—	—	—	—	—	5	735
Dividends payable (common and preferred)	59	—	(87)	—	90	—	—	62
Total liabilities from financing activities	4,150	173	(301)	1	90	(39)	(10)	4,064

(1) Includes an increase in issuance of long-term debt of $173 million.
(2) Includes a net decrease of $114 million in borrowings under credit facilities, a decrease of $92 million related to the repayment of long-term debt and a decrease in finance lease obligations of $8 million.

35. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	**2022**	2021	**Increase/ (decrease)**
Long-term debt(1)	**3,653**	3,267	**386**
Exchangeable securities	**739**	735	**4**
Bank overdraft	**16**	—	**16**
Equity			
Common shares	**2,863**	2,901	**(38)**
Preferred shares	**942**	942	**—**
Contributed surplus	**41**	46	**(5)**
Deficit	**(2,514)**	(2,453)	**(61)**
Accumulated other comprehensive income (loss)	**(222)**	146	**(368)**
Non-controlling interests	**879**	1,011	**(132)**
Less: available cash and cash equivalents	**(1,134)**	(947)	**(187)**
Less: principal portion of restricted cash on TransAlta OCP bonds(3)	**(17)**	(17)	**—**
Less: fair value asset of hedging instruments on long-term debt(4)	**(3)**	(2)	**(1)**
Total capital	**5,243**	5,629	**(386)**

(1) Includes lease liabilities, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.
(2) The Company 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 Company includes the principal portion of restricted cash on TransAlta OCP bonds as this cash is restricted specifically to repay outstanding debt.
(4) The Company 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 Company's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Company 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 Company to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also allows our commercial team to contract the Company's portfolio with a variety of counterparties on terms and prices that are favourable to the Company's financial results and provides the Company with better access to capital markets through commodity and credit cycles. The Company has an investment grade credit rating from DBRS Morningstar ("DBRS") (stable outlook). In 2022, Moody's reaffirmed the Company's Long Term Rating of Ba1 with a stable outlook. DBRS reaffirmed the Company's issuer rating and Unsecured Debt/Medium-Term Notes rating of BBB (low) and the Company's Preferred Shares rating of Pfd-3 (low), all with stable outlook. In addition, S&P Global Ratings reaffirmed the Company's Senior Unsecured Debt rating and Issuer Credit Rating of BB+ with stable outlook. The Company remains focused on maintaining a strong financial position and cash flow coverage ratios. Credit ratings provide information relating to the Company's financing costs, liquidity and operations and affect the Company's ability to obtain short-term and long-term financing and/or the cost of such financing.

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. Liquidity

For the years ended Dec. 31, 2022 and 2021, cash inflows and outflows are summarized below. The Company manages variations in working capital using existing liquidity under credit facilities to ensure sufficient cash and credit are available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

Year ended Dec. 31	2022	2021	Increase (decrease)
Cash flow from operating activities	**877**	1,001	**(124)**
Change in non-cash working capital	**316**	(174)	**490**
Cash flow from operations before changes in working capital	**1,193**	827	**366**
Dividends paid on common shares	**(54)**	(48)	**(6)**
Dividends paid on preferred shares	**(43)**	(39)	**(4)**
Distributions paid to subsidiaries' non-controlling interests	**(187)**	(156)	**(31)**
Property, plant and equipment expenditures	**(918)**	(480)	**(438)**
Inflow (outflow)	**(9)**	104	**(113)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2022, $1.0 billion (2021 – $1.3 billion) of the Company'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 maintain its capital structure and credit metrics within targeted ranges.

36. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2022, 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 Company and its subsidiaries have been eliminated on consolidation and are not disclosed. Associates and joint ventures have been equity accounted for by the Company.

A. Transactions with Key Management Personnel

TransAlta's key management personnel include the President and Chief Executive Officer ("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	**2022**	2021	2020
Total compensation	**23**	30	27
Comprised of:			
Short-term employee benefits	**11**	14	12
Post-employment benefits	**1**	1	2
Share-based payments	**11**	15	13

B. TransAlta Renewables Acquisitions

North Carolina Solar

On Nov. 5, 2021, TransAlta completed the sale of a 100 per cent economic interest in the 122 MW portfolio of solar facilities in North Carolina for US$102 million. Pursuant to the transaction, a TransAlta subsidiary owns the North Carolina Solar facility directly and another subsidiary issued tracking preferred shares to TransAlta Renewables reflecting the economic interest in the facilities.

Ada and Skookumchuck

On April 1, 2021, the Company completed the sale of its 100 per cent economic interest in the 29 MW Ada cogeneration facility and its 49 per cent economic interest in the 137 MW Skookumchuck wind facility to TransAlta Renewables for $43 million and $103 million, respectively. Pursuant to the transaction, a TransAlta subsidiary owns Ada and Skookumchuck directly and another subsidiary issued tracking preferred shares to TransAlta Renewables reflecting the economic interest in the facilities.

Big Level and Antrim

During 2021, TransAlta Renewables subscribed for additional tracking preferred shares in Big Level and Antrim for $7 million (US$6 million). In addition, TransAlta Renewables repaid a portion of the total outstanding promissory notes to the Company related to the Big Level and Antrim wind facilities in the amount of $18 million (US$14 million).

Windrise Wind

On Feb. 26, 2021, TransAlta completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind facility to TransAlta Renewables, for $213 million.

WindCharger

On Aug. 1, 2020, the WindCharger battery storage project was sold to TransAlta Renewables for $12 million.

C. Repayment of the TransAlta Energy (Australia) ("TEA") loan

On Oct. 23, 2022, the outstanding intercompany loan balance of AU$157 million, plus all accrued and unpaid interest, between TransAlta Renewables and TEA was fully repaid. The funds repaid will be reserved within TEA and restricted to fund future growth in Australia that TransAlta Renewables has elected to participate in, including the Northern Goldfields Solar and Battery project and the Mount Keith 132kV expansion project.

D. Transactions with Associates

In connection with the exchangeable securities issued to Brookfield, the investment agreement entitles Brookfield to nominate two directors to the TransAlta Board. This allows Brookfield to participate in the financial and operating policy decisions of the Company, and as such, they are considered associates of the Company.

In addition to the exchangeable securities disclosed in Note 26, the Company may, in the normal course of operations, enter into transactions on market terms with related parties that have been measured at exchange value and recognized in the consolidated financial statements, including power purchase and sale agreements, derivative contracts and asset management fees. Transactions and balances between the Company and associates do not eliminate.

Transactions with Brookfield include the following:

Year ended Dec. 31	2022	2021	2020
Power sales	**127**	27	10
Purchased power	**12**	3	3
Asset management fees paid	**2**	2	1

37. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Company 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:

	2023	2024	2025	2026	2027	2028 and thereafter	Total
Natural gas, transportation and other contracts	56	47	45	45	46	457	**696**
Transmission	10	7	7	3	1	39	**67**
Coal supply agreements	83	87	71	—	—	—	**241**
Long-term service agreements	51	49	35	32	21	140	**328**
Operating leases	3	3	3	2	2	29	**42**
Growth	446	—	—	—	—	—	**446**
TransAlta Energy Transition Bill	6	—	—	—	—	—	**6**
Total	**655**	**193**	**161**	**82**	**70**	**665**	**1,826**

Commitments

A. Natural Gas, Transportation and Other Contracts

The Company has fixed price or volume natural gas purchase and transportation contracts. Included in these contracts are 15-year natural gas transportation agreements for a total of 400 terajoules ("TJ") per day on a firm basis to 2036 and an eight-year natural gas transportation agreement for 75 TJ per day related to the Sheerness facility that is expected to end in 2030.

B. Transmission

The Company has several agreements to purchase transmission network capacity in Canada and the Pacific Northwest. Provided certain conditions for delivering the service are met, the Company 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 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.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections, repairs and maintenance that may be required on natural gas facilities, equipment for gas and turbines at various wind facilities.

E. Operating Leases

Operating leases include lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

F. Growth

Commitments for growth relate to the following projects: Horizon Hill wind project, White Rock wind projects, Garden Plain wind project, Northern Goldfields Solar project and the Mount Keith 132kV expansion.

The current estimate of the capital expenditures related to the Kent Hills rehabilitation is approximately $120 million, inclusive of insurance proceeds. Refer to Note 19 for amounts spent in 2022.

G. TransAlta Energy Transition Bill Commitments

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent Memorandum of Agreement ("MOA"), the Company has 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 portion thereof would no longer be required. As of Dec. 31, 2022, the Company has funded approximately US$50 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

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 Company'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 Company responds as required.

The Company conducts internal reviews of its offers and offer behaviour in both the energy and ancillary services markets in Alberta on an ongoing basis and will self-report suspected contraventions or respond to inquiries from regulatory agencies as required. There currently is no certainty that any particular matter will be resolved in the Company's favour or that such matters may not have a material adverse effect on TransAlta.

I. Brazeau Facility - Claim against the Government of Alberta

On Sept. 9, 2022, the Company filed a Statement of Claim against the Government of Alberta in the Alberta Court of King's Bench seeking a declaration that: (i) granting mineral leases within five kilometres of the Brazeau facility is a breach of a 1960 agreement between the Company and the Government of Alberta; and (ii) the Government of Alberta is required to indemnify the Company for any costs or damages that result from the risks of hydraulic fracturing near the Brazeau facility. On Sept. 29, 2022, the Government of Alberta filed its Statement of Defence, which asserts, among other things, that the Company: (i) is trying to usurp the jurisdiction of the Alberta Energy Regulator ("AER"); and (ii) is out of time under the Limitations Act (Alberta). The trial is scheduled to take place during the first quarter of 2024.

II. Brazeau Facility - Well License Applications to Consider Hydraulic Fracturing

The AER issued a subsurface order on May 27, 2019 that does not permit any hydraulic fracturing within three kilometres of the Brazeau facility but permits fracking in all formations (except the Duvernay) from three-to-five kilometres of the Brazeau facility. Subsequently, two oil and gas operators submitted applications to the AER for approval of 10 well licences (which include hydraulic fracturing activities) within three-to-five kilometres of the Brazeau facility. The regulatory hearing to consider the applications - Proceeding 379 - is currently scheduled to be heard between Feb. 27 and March 10, 2023. The Company's position is that hydraulic fracturing activities within any formation within five kilometres of the Brazeau Facility pose an unacceptable risk and that the applications should be denied.

III. Hydro PPA - Emission Performance Credits

Balancing Pool is claiming entitlement to the Emission Performance Credits ("EPCs") earned by the Alberta Hydro facilities as a result of those facilities being opted into the Carbon Competitiveness Incentive Regulation and Technology Innovation and Emissions Reduction Regulation from 2018 to 2020, inclusive. The Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro Power Purchase Arrangement require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs nor from any purported change-in-law and believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and the hearing was scheduled for Feb. 6 to 10, 2023. However, due to the resignation of one of the panel members, the hearing has been adjourned. A new panel member has been appointed and a two-week hearing will be held from May 18 to June 1, 2023. TransAlta holds approximately 1,750,000 EPCs with no recorded book value that were created between 2018 and 2020, which are at risk as a result of the Balancing Pool's claim.

IV. Sundance A Decommissioning

TransAlta filed an application with the Alberta Utilities Commission ("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 the second half of 2023.

38. Segment Disclosures

A. Description of Reportable Segments

The Company has six reportable segments as described in Note 1.

The following tables provides each segment's results in the format that the TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM"), review the Company's segments to make operating decisions and assess performance. The CODM assesses the performance of the operating segments based on a measure of adjusted EBITDA. This measurement basis represents earnings before income taxes, adjusted for the effects of: depreciation of property, plant and equipment and amortization of intangibles, depreciation of right-of-use assets, finance lease income, unrealized mark-to-market gains or losses, gains and losses related to closed positions effectively settled by offsetting positions with exchanges recorded in the year the positions are settled, unrealized foreign exchange gains or losses on commodity transactions, depreciation on our mining equipment included in fuel and purchased power, interest income recorded on the prepaid funds, write-down of coal inventory and parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities, going off-coal which resulted in the remaining coal supply payments on the existing coal supply agreement being recognized as an onerous contract, impairment charges, share of (profit) loss of joint venture and other costs or income adjustments. The tables below show the reconciliation of the total segmented results and adjusted EBITDA to the statement of earnings (loss) reported under IFRS. Prior periods have been adjusted for comparable purposes.

For internal reporting purpose, the earnings information from the Company's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Company'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.

B. Reported Adjusted Segment Earnings (Loss) and Segment Assets

I. Reconciliation of Adjusted EBITDA to Earnings before Income Tax

Year ended Dec. 31, 2022	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	606	303	1,209	714	160	(2)	2,990	(14)	—	2,976
Reclassifications and adjustments:										
Unrealized mark-to-market loss	1	104	251	10	12	—	378	—	(378)	—
Realized (gain) loss on closed exchange positions	—	—	(4)	—	47	—	43	—	(43)	—
Decrease in finance lease receivable	—	—	46	—	—	—	46	—	(46)	—
Finance lease income	—	—	19	—	—	—	19	—	(19)	—
Unrealized foreign exchange gain on commodity	—	—	—	—	(1)	—	(1)	—	1	—
Adjusted revenues	607	407	1,521	724	218	(2)	3,475	(14)	(485)	2,976
Fuel and purchased power	22	31	641	566	—	3	1,263	—	—	1,263
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Adjusted fuel and purchased power	22	31	637	566	—	3	1,259	—	4	1,263
Carbon compliance	—	1	83	(1)	—	(5)	78	—	—	78
Gross margin	585	375	801	159	218	—	2,138	(14)	(489)	1,635
OM&A	55	68	195	69	35	101	523	(2)	—	521
Taxes, other than income taxes	3	12	15	4	—	1	35	(2)	—	33
Net other operating (income) loss	—	(23)	(38)	—	—	—	(61)	3	—	(58)
Insurance recovery	—	7	—	—	—	—	7	—	(7)	—
Adjusted net other operating (income) loss	—	(16)	(38)	—	—	—	(54)	3	(7)	(58)
Adjusted EBITDA[2]	527	311	629	86	183	(102)	1,634			
Equity income										9
Finance lease income										19
Depreciation and amortization										(599)
Asset impairment charges										(9)
Net interest expense										(262)
Foreign exchange gain										4
Gain on sale of assets and other										52
Earnings before income taxes										353

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Year ended Dec. 31, 2021	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	383	323	1,109	709	211	4	2,739	(18)	—	2,721
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	25	(40)	19	(38)	—	(34)	—	34	—
Realized (gain) loss on closed exchange positions[2]	—	—	(6)	—	29	—	23	—	(23)	—
Decrease in finance lease receivable	—	—	41	—	—	—	41	—	(41)	—
Finance lease income	—	—	25	—	—	—	25	—	(25)	—
Unrealized foreign exchange gain on commodity	—	—	(3)	—	—	—	(3)	—	3	—
Adjusted revenues	383	348	1,126	728	202	4	2,791	(18)	(52)	2,721
Fuel and purchased power	16	17	457	560	—	4	1,054	—	—	1,054
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(79)	(111)	—	—	(190)	—	190	—
Coal inventory write-down	—	—	—	(17)	—	—	(17)	—	17	—
Adjusted fuel and purchased power	16	17	374	432	—	4	843	—	211	1,054
Carbon compliance	—	—	118	60	—	—	178	—	—	178
Gross margin	367	331	634	236	202	—	1,770	(18)	(263)	1,489
OM&A	42	59	175	117	36	84	513	(2)	—	511
Reclassifications and adjustments:										
Parts and materials write-down	—	—	(2)	(26)	—	—	(28)	—	28	—
Curtailment gain	—	—	—	6	—	—	6	—	(6)	—
Adjusted OM&A	42	59	173	97	36	84	491	(2)	22	511
Taxes, other than income taxes	3	10	13	6	—	1	33	(1)	—	32
Net other operating loss (income)	—	—	(40)	48	—	—	8	—	—	8
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	—	—	—	(48)	—	—	(48)	—	48	—
Adjusted net other operating loss (income)	—	—	(40)	—	—	—	(40)	—	48	8
Adjusted EBITDA[3]	322	262	488	133	166	(85)	1,286			
Equity income										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment charges										(648)
Net interest expense										(245)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										(380)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

Year ended Dec. 31, 2020	Hydro	Wind & Solar[1]	Gas	Energy Transition	Energy Marketing	Corporate	Total	Equity accounted investments[1]	Reclass adjustments	IFRS financials
Revenues	152	332	787	704	122	7	2,104	(3)	—	2,101
Reclassifications and adjustments:										
Unrealized mark-to-market (gain) loss	—	2	33	(14)	21	—	42	—	(42)	—
Realized gain on closed exchange positions[2]	—	—	—	—	(10)	—	(10)	—	10	—
Decrease in finance lease receivable	—	—	17	—	—	—	17	—	(17)	—
Finance lease income	—	—	7	—	—	—	7	—	(7)	—
Unrealized foreign exchange loss on commodity	—	—	4	—	—	—	4	—	(4)	—
Adjusted revenues	152	334	848	690	133	7	2,164	(3)	(60)	2,101
Fuel and purchased power	8	25	325	435	—	12	805	—	—	805
Reclassifications and adjustments:										
Australian interest income	—	—	(4)	—	—	—	(4)	—	4	—
Mine depreciation	—	—	(100)	(46)	—	—	(146)	—	146	—
Coal inventory write-down	—	—	—	(37)	—	—	(37)	—	37	—
Adjusted fuel and purchased power	8	25	221	352	—	12	618	—	187	805
Carbon compliance	—	—	120	48	—	(5)	163	—	—	163
Gross margin	144	309	507	290	133	—	1,383	(3)	(247)	1,133
OM&A	37	53	166	106	30	80	472	—	—	472
Taxes, other than income taxes	2	8	13	9	—	1	33	—	—	33
Net other operating income	—	—	(11)	—	—	—	(11)	—	—	(11)
Reclassifications and adjustments:										
Impact of Sheerness going off-coal	—	—	(28)	—	—	—	(28)	—	28	—
Adjusted net other operating income	—	—	(39)	—	—	—	(39)	—	28	(11)
Adjusted EBITDA[3]	105	248	367	175	103	(81)	917			
Equity income										1
Finance lease income										7
Depreciation and amortization										(654)
Asset impairment charges										(84)
Net interest expense										(238)
Foreign exchange gain										17
Gain on sale of assets and other										9
Loss before income taxes										(303)

(1) The Skookumchuck wind facility has been included on a proportionate basis in the Wind and Solar segment.
(2) In 2022, our adjusted EBITDA composition was adjusted to include the impact of closed positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	**437**	**2,837**	**1,858**	**313**	**—**	**111**	**5,556**
Right-of-use assets	**6**	**98**	**6**	**2**	**—**	**14**	**126**
Intangible assets	**2**	**157**	**49**	**5**	**8**	**31**	**252**
Goodwill	**258**	**176**	—	—	**30**	**—**	**464**

As at Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
PP&E	466	2,304	2,036	481	—	33	5,320
Right-of-use assets	5	64	7	1	—	18	95
Intangible assets	3	147	56	9	5	36	256
Goodwill	258	175	—	—	30	—	463

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2022	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	**36**	**745**	**43**	**19**	**—**	**75**	**918**
Intangible assets	**—**	**19**	**—**	**—**	**3**	**9**	**31**

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	29	166	167	90	—	28	480
Intangible assets	—	—	—	1	—	8	9

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas	Energy Transition	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	22	174	199	78	—	13	486
Intangible assets	—	—	—	1	—	13	14

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	2022	2021	2020
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**599**	529	654
Depreciation included in fuel and purchased power (Note 6)	**—**	190	144
Depreciation and amortization on the Consolidated Statements of Cash Flows	**599**	719	798

C. Geographic Information

I. Revenues

Year ended Dec. 31	2022	2021	2020
Canada	**1,905**	1,854	1,227
US	**940**	731	716
Australia	**131**	136	158
Total revenue	**2,976**	2,721	2,101

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	2022	2021	2022	2021	2022	2021	2022	2021
Canada	**3,817**	4,051	**49**	52	**123**	141	**62**	15
US	**1,307**	860	**74**	39	**101**	85	**34**	61
Australia	**432**	409	**3**	4	**28**	30	**64**	66
Total	**5,556**	5,320	**126**	95	**252**	256	**160**	142

D. Significant Customer

For the year ended Dec. 31, 2022, sales to the AESO represented 60 per cent of the Company's total revenue (2021 – sales to the AESO represented 35 per cent of the Company's total revenue). There were no other companies that accounted for more than 10 per cent of the Company's total revenue.

39. Subsequent Events

Early-Stage Pumped Hydro Development Project

On Feb. 16, 2023, the Company announced that it had entered into a definitive agreement to acquire a 50 per cent interest in the Tent Mountain Renewable Energy Complex ("Tent Mountain"), an early-stage 320 MW pumped hydro energy storage development project, located in southwest Alberta, currently owned by Montem Resources Limited ("Montem"). The acquisition includes the land rights, fixed assets and intellectual property associated with the pumped hydro development project. The Company will pay Montem approximately $8 million upon closing the transaction with additional payments of up to $17 million (approximately $25 million total) contingent on the achievement of specific development and commercial milestones. The Company and Montem will form a partnership and jointly manage the project, with the Company acting as project developer. The acquisition also includes the intellectual property associated with a 100 MW offsite green hydrogen electrolyser and a 100 MW offsite wind development project. The closing of the transaction remains subject to customary closing conditions, including receipt by Montem of shareholder approval, with closing expected to occur in March 2023.

Eleven-Year Financial and Statistical Summary

(in millions of Canadian dollars, except where noted)

Year ended Dec. 31	2022	2021	2020
Financial Summary			
STATEMENT OF EARNINGS			
Revenues	**2,976**	2,721	2,101
Operating income (loss)	**531**	(239)	(99)
Earnings (loss) before income taxes	**353**	(380)	(303)
Net earnings (loss) attributable to common shareholders	**4**	(576)	(336)
STATEMENT OF FINANCIAL POSITION			
Total assets	**10,741**	9,226	9,747
Current portion of long-term debt, net of cash and cash equivalents	**(940)**	(103)	(598)
Credit facilities, long-term debt and finance lease obligations	**3,475**	2,423	3,256
Exchangeable securities	**739**	735	730
Non-controlling interests	**879**	1,011	1,084
Preferred shares	**942**	942	942
Equity attributable to common shareholders[1]	**168**	640	1,410
Principal portion of restricted cash on TransAlta OCP and fair value (asset) liability of hedging instruments on debt[1]	**(20)**	(19)	(13)
Total capital[2]	**5,243**	5,629	6,811
CASH FLOWS			
Cash flow from operating activities	**877**	1,001	702
Cash flow from (used in) investing activities	**(741)**	(472)	(687)
COMMON SHARE INFORMATION (per share)			
Net earnings (loss)	**0.01**	(2.13)	(1.22)
Comparable earnings[1]	**n/a**	n/a	n/a
Dividends declared on common share	**0.21**	0.19	0.22
Book value per common share (at year-end)[1]	**0.62**	2.37	5.13
Market price:			
High	**15.28**	14.61	11.23
Low	**10.52**	9.57	5.32
Close (Toronto Stock Exchange at Dec. 31)	**12.11**	14.05	9.67
RATIOS (percentage except where noted)			
Adjusted net debt to adjusted EBITDA[1,3,4] (times)	**2.2**	2.6	4.0
Return on equity attributable to common shareholders[1]	**1.0**	(116.6)	(30.3)
Comparable return on equity attributable to common shareholders[1]	**n/a**	n/a	n/a
Return on capital employed[1]	**9.2**	(4.5)	(1.5)
Comparable return on capital employed[1]	**n/a**	n/a	n/a
Earnings coverage (times)[1]	**2.2**	(1.0)	(0.5)
Dividend payout ratio based on FFO[1,4]	**4.1**	5.1	7.0
Adjusted EBITDA[1,3,4] (in millions of Canadian dollars)	**1,634**	1,286	917
Dividend coverage[1,4] (times)	**18.3**	23.0	15.6
Dividend yield[1]	**1.7**	1.3	1.7
Weighted average common shares for the year (in millions)	**271**	271	275
Common shares outstanding at Dec. 31 (in millions)	**268**	271	270
STATISTICAL SUMMARY			
Number of employees	**1,282**	1,282	1,476
Gross installed capacity (MW)[5]			
Energy Transition [7]	**671**	1,472	2,548
Gas[6,8]	**3,084**	3,084	3,082
Renewables (wind, solar and hydro)	**2,828**	2,694	2,498
Equity investments	**67**	67	67
Total generating capacity	**6,650**	7,387	8,265
Total generation production (GWh)	**21,258**	22,105	24,980

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 2011 to 2014 has been revised to align with the 2015 calculation methodology.

2019	2018	2017	2016	2015	2014	2013	2012
2,347	2,249	2,307	2,397	2,267	2,623	2,292	2,210
335	160	138	478	148	442	195	(214)
193	(96)	(54)	314	221	239	(12)	(445)
52	(248)	(190)	117	(24)	141	(71)	(615)
9,508	9,428	10,304	10,996	10,947	9,833	9,624	9,503
102	59	433	334	33	708	175	582
2,699	3,119	2,960	3,722	4,408	3,305	4,130	3,610
326	—	—	—	—	—	—	—
1,101	1,137	1,059	1,152	1,029	594	517	330
942	942	942	942	942	942	781	—
2,019	2,055	2,384	2,569	2,419	2,342	2,125	3,018
(17)	(10)	(30)	(163)	(190)	(96)	(16)	50
7,172	7,275	7,748	8,556	8,641	7,795	7,712	7,590
849	820	626	744	432	796	765	520
(512)	(394)	87	(327)	(573)	(292)	(703)	(1,048)
0.18	(0.86)	(0.66)	0.41	(0.09)	0.52	(0.27)	(2.62)
n/a	n/a	n/a	0.13	(0.17)	0.25	0.31	0.50
0.12	0.20	0.16	0.3	0.72	0.83	1.16	1.16
7.14	7.16	8.28	8.92	8.52	8.52	7.92	8.78
10.14	7.90	8.50	7.54	12.34	14.94	16.86	21.37
5.50	5.44	6.88	3.76	4.13	9.81	12.91	14.11
9.28	5.59	7.45	7.43	4.91	10.52	13.48	15.12
3.9	3.6	3.6	3.8	5.4	4.2	4.6	4.6
3.3	(15.8)	(10.0)	5.4	(1.2)	6.3	(3.2)	(25.9)
n/a	n/a	n/a	1.7	(2.3)	3.0	3.7	4.9
4.1	0.7	2.1	5.3	4.6	5.8	2.8	(3.1)
n/a	n/a	n/a	4.4	3.0	5.1	5.2	5.3
1.5	0.2	0.6	1.7	1.5	1.7	0.8	(1.0)
6.6	6.1	4.3	8.1	30.0	26.4	43.1	25.1
984	1,123	1,062	1,144	867	1,036	1,023	1,015
18.6	18.3	14.1	11.1	3.3	5.7	6.3	4.7
1.7	2.9	2.1	4.0	14.7	7.9	8.6	7.7
283	287	288	288	280	273	264	235
277	285	288	288	284	275	268	255
1,543	1,883	2,228	2,341	2,380	2,786	2,772	2,084
2,915	3,147	3,707	3,707	3,708	3,693	3,693	3,140
3,049	2,819	2,827	2,906	2,823	2,949	3,197	3,142
2,421	2,308	2,289	2,334	2,350	2,204	2,202	2,058
—	—	—	—	—	—	396	390
8,385	8,273	8,823	8,947	8,881	8,846	9,488	8,730
29,071	28,409	36,900	38,157	40,673	45,002	42,482	38,750

(3) In 2022, the adjusted EBITDA composition was amended to include the impact of closed exchange positions that are effectively settled by offsetting positions with the same counterparty to reflect the performance of the assets and the Energy Marketing segment in the period in which the transactions occur. Therefore, the Company has applied this composition to 2022, 2021, and 2020 only. In 2019 and onwards adjusted 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.
(7) In 2021, Gas was adjusted to include the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.
(8) In 2021, Energy Transition was adjusted to include the segments previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal. Prior year figures were revised.

Ratio Formulas

Adjusted net debt to Adjusted EBITDA = long-term debt and lease liabilities including current portion + exchangeable securities + 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 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 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 = earnings (loss) before income taxes + net interest expense / 50 per cent dividends paid on preferred shares + interest on debt - interest income

Dividend payout ratio based on FFO = common share dividends paid / 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 closing price

Plant Summary

As at Dec. 31, 2022	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1][2]	Region	Revenue source	Contract expiry date
Hydro	Brazeau, AB	355	100 %	355	100 %	355	Western Canada	Merchant	—
24 facilities	Bighorn, AB	120	100 %	120	100 %	120	Western Canada	Merchant	—
	Spray, AB	112	100 %	112	100 %	112	Western Canada	Merchant	—
	Ghost, AB	54	100 %	54	100 %	54	Western Canada	Merchant	—
	Rundle, AB	50	100 %	50	100 %	50	Western Canada	Merchant	—
	Cascade, AB	36	100 %	36	100 %	36	Western Canada	Merchant	—
	Kananaskis, AB	19	100 %	19	100 %	19	Western Canada	Merchant	—
	Bearspaw, AB	17	100 %	17	100 %	17	Western Canada	Merchant	—
	Pocaterra, AB	15	100 %	15	100 %	15	Western Canada	Merchant	—
	Horseshoe, AB	14	100 %	14	100 %	14	Western Canada	Merchant	—
	Barrier, AB	13	100 %	13	100 %	13	Western Canada	Merchant	—
	Taylor, AB*	13	100 %	13	100 %	13	Western Canada	Merchant	—
	Interlakes, AB	5	100 %	5	100 %	5	Western Canada	Merchant	—
	Belly River, AB*	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Three Sisters, AB	3	100 %	3	100 %	3	Western Canada	Merchant	—
	Waterton, AB*	3	100 %	3	100 %	3	Western Canada	Merchant	—
	St. Mary, AB*	2	100 %	2	100 %	2	Western Canada	Merchant	—
	Upper Mamquam, BC*	25	100 %	25	100 %	25	Western Canada	LTC[12]	2025
	Pingston, BC*	45	50 %	23	100 %	23	Western Canada	LTC	2023
	Bone Creek, BC*	19	100 %	19	100 %	19	Western Canada	LTC	2031
	Akolkolex, BC*	10	100 %	10	100 %	10	Western Canada	LTC	2046
	Ragged Chute, ON*	7	100 %	7	100 %	7	Eastern Canada	LTC	2029
	Misema, ON*	3	100 %	3	100 %	3	Eastern Canada	LTC	2027
	Moose Rapids, ON*	1	100 %	1	100 %	1	Eastern Canada	LTC	2030
Total Hydro		**944**		**922**		**922**			
Wind &	Summerview 1, AB*	68	100 %	68	100 %	68	Western Canada	Merchant	—
Battery Storage	Summerview 2, AB*	66	100 %	66	100 %	66	Western Canada	Merchant	—
27 facilities	Ardenville, AB*	69	100 %	69	100 %	69	Western Canada	Merchant	—
	Blue Trail and Macleod Flats, AB*	69	100 %	69	100 %	69	Western Canada	Merchant	—
	Castle River, AB*[3]	44	100 %	44	100 %	44	Western Canada	Merchant	—
	McBride Lake, AB*	75	50 %	38	100 %	38	Western Canada	LTC	2024
	Soderglen, AB*	71	50 %	36	100 %	36	Western Canada	Merchant	—
	Cowley North, AB*	20	100 %	20	100 %	20	Western Canada	Merchant	—
	Oldman, AB*	4	100 %	4	100 %	4	Western Canada	Merchant	—
	Sinnott, AB*	7	100 %	7	100 %	7	Western Canada	Merchant	—
	Windrise, AB*	206	100 %	206	100 %	206	Western Canada	LTC	2041
	WindCharger battery storage, AB*	10	100 %	10	100 %	10	Western Canada	Merchant	—

Plant Summary

As at Dec. 31, 2022	Facility	Nameplate capacity (MW)[1]	Consolidated interest	Gross installed capacity[1]	Ownership (%)	Net capacity ownership interest (MW)[1][2]	Region	Revenue source	Contract expiry date
	Melancthon, ON*[4]	200	100 %	200	100 %	200	Eastern Canada	LTC	2028-2031
	Wolfe Island, ON*	198	100 %	198	100 %	198	Eastern Canada	LTC	2029
	Kent Breeze, ON*	20	100 %	20	100 %	20	Eastern Canada	LTC	2031
	Kent Hills, NB*[5]	167	100 %	167	83 %	139	Eastern Canada	LTC	2045
	Le Nordais, QC*	98	100 %	98	100 %	98	Eastern Canada	LTC	2033
	New Richmond, QC*	68	100 %	68	100 %	68	Eastern Canada	LTC	2033
	Wyoming Wind, WY*	140	100 %	140	100 %	140	United States	LTC	2028
	Lakeswind, MN*	50	100 %	50	100 %	50	United States	LTC	2034
	Big Level, PA*	90	100 %	90	100 %	90	United States	LTC	2034
	Antrim, NH*	29	100 %	29	100 %	29	United States	LTC	2039
	Skookumchuck, WA[6]	137	49 %	67	100 %	67	United States	LTC	2040
Total Wind		**1,906**		**1,763**		**1,735**			
Solar	Mass Solar, MA*[7]	21	100 %	21	100 %	21	United States	LTC	2032-2035
2 facilities	North Carolina Solar, NC[8]	122	100 %	122	100 %	122	United States	LTC	2033
Total Solar		**143**		**143**		**143**			
Gas	Keephills 2, AB	395	100 %	395	100 %	395	Western Canada	Merchant	—
17 facilities	Keephills 3, AB	463	100 %	463	100 %	463	Western Canada	Merchant	—
	Poplar Creek, AB[9]	230	100 %	230	100 %	230	Western Canada	LTC	2030
	Sheerness, AB[4]	800	50 %	400	50 %	200	Western Canada	Merchant	—
	Sundance 6, AB	401	100 %	401	100 %	401	Western Canada	Merchant	—
	Fort Saskatchewan, AB	118	60 %	71	50 %	35	Western Canada	LTC/ Merchant	2029
	Sarnia, ON*	499	100 %	499	100 %	499	Eastern Canada	LTC	2031
	Ottawa, ON	74	100 %	74	50 %	37	Eastern Canada	LTC/ Merchant	2033
	Windsor, ON	72	100 %	72	50 %	36	Eastern Canada	LTC/ Merchant	2031
	Ada, MI*[6]	29	100 %	29	100 %	29	United States	LTC	2026
	Parkeston, WA*[11]	110	50 %	55	100 %	55	Australia	LTC	2026
	Southern Cross, WA*[10][11]	245	100 %	245	100 %	245	Australia	LTC	2038
	South Hedland, WA*[11]	150	100 %	150	100 %	150	Australia	LTC	2042
Total Gas		**3,586**		**3,084**		**2,775**			
Energy Transition	Centralia, WA	670	100 %	670	100 %	670	United States	LTC/ Merchant	2025[13]
2 facilities	Skookumchuck, WA	1	100 %	1	100 %	1	United States	LTC	2025
Total Energy Transition		**671**		**671**		**671**			
Total		**7,250**		**6,583**		**6,246**			

* TransAlta Renewables Inc. facility.
(1) Megawatts are rounded to the nearest whole number; columns may not add due to rounding. The gross installed capacity reflects the basis of consolidation of underlying assets owned,
net capacity ownership interest deducts capacity attributable to non-controlling interest in these assets and is calculated after consolidation of underlying assets.
(2) Includes 100% of TransAlta Renewables assets. As of Dec. 31, 2022, TransAlta owns approximately 60% of the outstanding shares of TransAlta Renewables.
(3) Includes seven individual turbines at other locations.
(4) Comprised of two facilities.
(5) Comprised of three facilities.
(6) Effective Jan. 1, 2021, facility has been sold to TransAlta Renewables.
(7) Comprised of four ground-mounted sites and four roof-top sites.
(8) Comprised of 20 sites.
(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) LTC refers to Long-Term Contract.
(13) 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.

Sustainability Performance Indicators

Corporate Statistics

Environment Health & Safety ("EHS") Management Systems	2022	2021	2020
EHS management system audits[1]	**4**	4	8
Health and Safety compliance audits[2]	**9**	11	11
Total EHS audits	**13**	15	19

Environmental Performance [3]	2022	2021	2020
Resource or energy use[4]			
Coal combustion (tonnes)	**2,181,000**	4,094,000	6,637,000
Natural gas combustion (GJ)	**130,023,000**	106,768,000	82,917,000
Diesel combustion (L)	**6,706,000**	7,596,000	6,955,000
Gasoline consumption: vehicle (L)	**609,000**	864,000	933,000
Diesel consumption: vehicle (L)	**3,275,000**	6,705,000	10,971,000
Propane consumption: vehicle (L)	**12,000**	6,000	6,000
Electricity: building operations (MWh)	**152,000**	174,000	186,000
Natural gas: building operations (GJ)	**35,000**	119,000	135,000
Propane: building operations (L)	**169,000**	189,000	198,000
Kerosene: building operations (L)	**3,000**	65,000	48,000
Total resource or energy use (GJ)	**194,954,000**	203,716,000	278,977,000
Greenhouse gas emissions[5]			
Carbon dioxide (tonnes CO_2e)	**10,183,000**	12,420,000	16,246,000
Methane (tonnes CO_2e)	**24,000**	25,000	34,000
Nitrous oxide (tonnes CO_2e)	**41,000**	59,000	80,000
Sulphur hexafluoride (tonnes CO_2e)	**200**	370	110
Total greenhouse gas emissions (tonnes CO_2e)[6] √	**10,248,000**	12,505,000	16,361,000
Greenhouse gas emission intensity (tonnes CO_2e/MWh)[7] √	**0.40**	0.60	0.67
Scope 1 emissions (% of total GHG emissions)	**99**	99	99
Scope 2 emissions (% of total GHG emissions)	**1**	1	1
Scope 1 emissions reported to national regulatory bodies (%)	**100**	100	100
Air emissions[8]			
Total sulphur dioxide emissions (tonnes) √	**1,000**	7,000	12,000
Sulphur dioxide emission intensity (kg/MWh) √	**0.05**	0.35	0.49
Total nitrogen oxide emissions (tonnes) √	**11,000**	14,000	21,000
Nitrogen oxide emission intensity (kg/MWh) √	**0.43**	0.69	0.88
Total particulate matter emissions (tonnes) √	**400**	2,200	4,000
Particulate matter emission intensity (kg/MWh) √	**0.02**	0.11	0.16
Total mercury emissions (kilograms) √	**20**	40	60
Mercury emission intensity (mg/MWh) √	**0.77**	1.94	2.33

Environmental Performance (continued)	2022	2021	2020
Water management[9]			
Water withdrawal – water utility/municipality/customer (million m^3)	**230**	240	230
Water withdrawal – surface water (million m^3)	**0**	0	0
Water withdrawn – all sources (million m^3) √	**230**	240	230
Water discharge – all sources (million m^3) √	**210**	210	200
Water consumption (million m^3) √	**20**	30	40
Water consumption intensity (m^3/MWh)[10] √	**1.03**	1.52	1.47
Waste management[11]			
Non-hazardous[12]			
Landfill (tonnes) √	**1,800**	1,000	11,000
Landfill (L) √	**76,200**	55,000	55,000
Ash disposal: mine (tonnes)[13] √	**2,910**	232,000	408,000
Ash disposal: lagoon (tonnes)[14] √	**0**	44,000	98,000
Recycled (tonnes) √	**1,600**	4,000	8,000
Recycled (L)[15] √	**2,103,000**	1,765,000	1,855,000
Reuse (tonnes) √	**151,000**	176,000	533,000
Storage (tonnes) √	**26,000**	31,000	53,000
Compostable (tonnes)	**0**	10	10
Hazardous[16]			
Landfill (tonnes) √	**80**	220	20
Landfill (L) √	**52,000**	26,000	59,000
Recycled (tonnes) √	**0**	10	20
Recycled (L) √	**21,019,000**	22,837,000	20,090,000
Land use and reclamation[17]			
Land used in mining activities – disturbed (cumulative hectares) √	**12,600**	12,600	12,600
Land used in mining activities – reclaimed (cumulative hectares) √	**4,800**	4,800	4,800
Reclamation of land used in mining activities (% of land disturbed) √	**38**	38	38
Land used in mining activities: disturbed minus reclaimed (hectares) √	**7,800**	7,700	7,700
Land used by facilities, offices and equipment (hectares) √	**5,000**	5,000	4,900
Total land use (cumulative hectares) √	**12,700**	12,700	12,600
Environmental incidents[18]			
Significant environmental incidents	**0**	0	6
Regulatory non-compliance environmental incidents	**1**	2	2
Total significant environmental incidents √	**1**	2	8
Environmental enforcement actions[19]	**2**	1	0
Environmental fines ($ thousands)	**35**	3	0
Environmental spills[20]			
Volume of significant environmental spills (m^3)	**246**	6	4

Social Performance	2022	2021	2020
Workplace practices			
Employees	**1,222**	1,282	1,476
Number of full-time employees	**1,150**	1,181	1,392
Number of part-time employees	**14**	15	16
Number of contingent employees	**58**	86	68
Employees represented by independent trade union organizations (%)[(21)]	**31**	33	41
Voluntary employee turnover rate (%)[(22)]	**9**	8	9
Diversity			
Women in workforce (% of all employees)	**26**	24	21
Women in senior management (%)	**30**	38	43
Women on Board of Directors (%)	**36**	42	45
Health and safety			
Health and safety enforcement actions[(23)]	**0**	0	0
Health and safety fines ($ thousands)	**0**	0	0
Employee & contractor fatalities √	**0**	0	0
Lost-time injury (LTI) incidents (absence from work)[(24)] √	**0**	3	5
Medical aid (MA) incidents (no absence from work)[(25)] √	**6**	9	9
Restricted work injury (RWI) incidents (no absence from work)[(26)] √	**0**	5	2
Total recordable injuries to employees and contractors √	**6**	17	16
Exposure hours[(27)]	**3,058,000**	4,134,000	3,948,000
Total Recordable Injury Frequency (TRIF) (employees and contractors)[(28)] √	**0.39**	0.82	0.81
Community relations			
Community investments ($ millions)[(29)]	**2.3**	3.0	2.2

√ 2022 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 GRI and SASB. Internally developed criteria are described in the footnotes to the Sustainability Performance Indicators.

Environment Health & Safety Management Systems	Alignment with GRI or SASB standards
EHS management system audits	Internally developed criteria
Health and Safety compliance audits	Internally developed criteria
Total EHS audits	

Environmental Performance	Alignment with GRI or SASB standards
Resource or energy use	GRI 302-1
Coal combustion (tonnes)	GRI 302-1
Natural gas combustion (GJ)	GRI 302-1
Diesel combustion (L)	GRI 302-1
Gasoline consumption: vehicle (L)	GRI 302-1
Diesel consumption: vehicle (L)	GRI 302-1
Propane consumption: vehicle (L)	GRI 302-1
Electricity: building operations (MWh)	GRI 302-1
Natural gas: building operations (GJ)	GRI 302-1
Propane: building operations (L)	GRI 302-1
Kerosene: building operations (L)	GRI 302-1
Total resource or energy use (GJ)	GRI 302-1
Greenhouse gas emissions	
Carbon dioxide (tonnes CO_2e)	SASB IF-EU-110a.1
Methane (tonnes CO_2e)	SASB IF-EU-110a.1
Nitrous oxide (tonnes CO_2e)	SASB IF-EU-110a.1
Sulphur hexafluoride (tonnes CO_2e)	SASB IF-EU-110a.1
Total greenhouse gas emissions (tonnes CO_2e)	SASB IF-EU-110a.1
Greenhouse gas emission intensity (tonnes CO_2e/MWh)	GRI 305-4
Scope 1 emissions (% of total GHG emissions)	SASB IF-EU-110a.1
Scope 2 emissions (% of total GHG emissions)	GRI 305-2
Scope 1 emissions reported to national regulatory bodies (%)	SASB IF-EU-110a.1
Air emissions	
Total sulphur dioxide emissions (tonnes)	SASB IF-EU-120a.1
Sulphur dioxide emission intensity (kg/MWh)	Internally developed criteria
Total nitrogen oxide emissions (tonnes)	SASB IF-EU-120a.1
Nitrogen oxide emission intensity (kg/MWh)	Internally developed criteria
Total particulate matter emissions (tonnes)	SASB IF-EU-120a.1

Particulate matter emission intensity (kg/MWh)	Internally developed criteria
Total mercury emissions (kilograms)	SASB IF-EU-120a.1
Mercury emission intensity (mg/MWh)	Internally developed criteria

Environmental Performance *(continued)*	**Alignment with GRI or SASB Standards**
Water management	
Water withdrawal – water utility/municipality/customer (million m^3)	SASB IF-EU-140a.1
Water withdrawal – surface water (million m^3)	SASB IF-EU-140a.1
Water withdrawn – all sources (million m^3)	SASB IF-EU-140a.1
Water discharge – all sources (million m^3)	SASB IF-EU-140a.1
Water consumption (million m^3)	SASB IF-EU-140a.1
Water intensity (m^3/MWh)	Internally developed criteria
Waste management	
Non-hazardous	
Landfill (tonnes)	GRI 306-2
Landfill (L)	GRI 306-2
Ash disposal: mine (tonnes)	GRI 306-2
Ash disposal: lagoon (tonnes)	GRI 306-2
Recycled (tonnes)	GRI 306-2
Recycled (L)	GRI 306-2
Reuse (tonnes)	GRI 306-2
Storage (tonnes)	GRI 306-2
Compostable (tonnes)	GRI 306-2
Hazardous	
Landfill (tonnes)	GRI 306-2
Landfill (L)	GRI 306-2
Recycled (tonnes)	GRI 306-2
Recycled (L)	GRI 306-2
Land use and reclamation	
Land used in mining activities – disturbed (cumulative hectares)	Internally developed criteria
Land used in mining activities – reclaimed (cumulative hectares)	Internally developed criteria
Reclamation of land used in mining activities (% of land disturbed)	Internally developed criteria
Land used in mining activities: disturbed minus reclaimed (hectares)	Internally developed criteria
Land used by plants, offices and equipment (hectares)	Internally developed criteria
Total land use (cumulative hectares)	Internally developed criteria
Environmental incidents	
Significant environmental incidents	Internally developed criteria

Regulatory non-compliance environmental incidents	GRI 307-1
Total significant environmental incidents	Internally developed criteria
Environmental enforcement actions	GRI 307-1
Environmental fines ($ thousands)	GRI 307-1
Environmental spills	
Volume of significant spills (m^3)	GRI 306-3

Social Performance	Alignment with GRI or SASB Standards
Workplace practices	
Employees	GRI 102-7
Number of full-time employees	Internally developed criteria
Number of part-time employees	Internally developed criteria
Number of contingent employees	Internally developed criteria
Employees represented by independent trade union organizations (%)	GRI 102-41
Voluntary employee turnover rate (%)	GRI 401-1
Diversity	
Women in workforce (% of all employees)	GRI 405-1
Women in senior management (%)	GRI 405-1
Women on Board of Directors (%)	GRI 405-1
Health and safety	
Health and safety enforcement actions	Internally developed criteria
Health and safety fines ($ thousands)	Internally developed criteria
Employee & contractor fatalities	SASB IF-EU-320a.1
Lost-time injury (LTI) incidents (absence from work)	SASB IF-EU-320a.1
Medical aid (MA) incidents (no absence from work)	SASB IF-EU-320a.1
Restricted work injury (RWI) incidents (no absence from work)	SASB IF-EU-320a.1
Total injuries to employees & contractors	SASB IF-EU-320a.1
Exposure hours	SASB IF-EU-320a.1
Total Recordable Injury Frequency (TRIF) (employees and contractors)	SASB IF-EU-320a.1
Community relations	
Community investments ($ millions)	GRI 203-1

Discussion and Notes on Numbers

TransAlta 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. EHS management system audits are conducted annually to assesses conformance to our environmental, health and safety management systems.
2. Health and Safety compliance audits are conducted to verify compliance to internal health and safety standards and procedures and defined occupational health and safety regulatory requirements.
3. We have updated some of our historical figures following a review of the data and a revision of our rounding methodology. Data revisions that are significant in magnitude have been discussed below. 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 <1000, 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 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.
5. 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 GHG 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 2 emissions. We compile our corporate GHG inventory using our business segment GHG calculations. 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, NPRI) and the US (EPA). Our scope 1 and 2 emissions use global warming potentials and emissions factors that vary with respect to regional compliance guidance and include IPCC 4th Assessment Report, Canada's GHG Inventory 1990-2019, US EPA eGRID Summary Tables 2019 and Australia NGERS Measurement Determination. Applying harmonized global warming potentials and emission factors across our fleet would result in a minor variance to our overall calculated GHG totals. An estimate of our scope 3 emissions can be found in our 2022 MD&A.
6. Gross GHG emissions or gross 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.
7. GHG emission intensity is calculated by dividing total operational emissions by 100 per cent of production (MWh) from operated facilities, irrespective of financial ownership. In 2022, our GHG emission intensity decreased from 2021 due to the different approach in calculating our total production to include steam generation, which was omitted in previous years. Therefore, intensity metrics are not comparable year over year.
8. Air emissions are calculated and reported from TransAlta-operated facilities, following the same approach we use for 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. Particulate matter emissions include both $PM_{2.5}$ and PM_{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. In 2022, our air emissions intensity decreased from 2021 due to the different approach in calculating our total production to include steam generation, which was omitted in previous years. Therefore, intensity metrics are not comparable year over year. Historical adjustments to 2021 particulate matter emissions and intensity were made to reflect accrual adjustments for road dust at our Highvale facility.
9. Water use is calculated and reported from TransAlta-operated facilities, following the same approach we use for 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 withdrawal, discharge and consumption values for 2020 were adjusted to reflect a new rounding approach.
10. 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. In 2022, our water intensity decreased from 2021 due to the different approach in calculating our total production to include steam generation, which was omitted in previous years. Therefore, intensity metrics are not comparable year over year. Minor historical adjustment to 2020 water consumption data (see Note 9) resulted in adjustments to 2020 water intensity data.
11. Adjustments were made to historical 2020 waste values to reflect accrued volumes from 2020 after we received final waste manifests as part of the reclamation project at our Mississauga facility. As a result, approximately 23,000 tonnes equivalent were added from Mississauga to multiple waste categories in 2020.

12. Non-hazardous waste includes, but is not limited to, the disposal of water treatment chemicals, coal refuse (including ash byproducts), metals, paper, cardboard and building materials. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge.
13. Ash disposal: mine is fly ash and bottom ash from coal production, which is treated and then returned to its original source, the mine, for landfill/disposal.
14. Ash disposal: lagoon is fly ash and bottom ash from Keephills coal production, which is treated and then sent to ash lagoons for disposal.
15. In 2021, we adjusted our reported 2020 non-hazardous waste recycled (L) volumes to reflect accrued volumes from our Sarnia facility.
16. 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. We measure and report the total weight of all types of waste generated and use several methods for calculation, including direct measurement of quantity on site, by transporters at the point of shipping or loading (consistent with shipping papers), by waste disposal contractor at the point of waste disposal or by transporters, at the point of shipping or loading, and engineering estimates or process knowledge.
17. Land used in mining activities – disturbed refers to the total active footprint of our mining operations, which includes the cumulative hectares for land cleared of vegetation, soil disturbed, ready for reclamation, soils placed, and permanently reclaimed: (i) Disturbed means soil has been disturbed; (ii) Cleared means vegetation has been removed and soils are intact; (iii) Reclamation means the restoration of disturbed lands to similar pre-development condition, other economically productive use, or natural or semi-natural habitat. Land reclamation refers to the ratio between the land that has been permanently or temporarily reclaimed and the total active footprint of our mining operations. Reclamation is presented as a cumulative number; therefore, the total number of hectares reported from year to year may increase depending on whether reclamation has occurred or whether re-disturbance of previously reclaimed areas was required. Total land use refers to the total active footprint of all our operations or the sum of the land used in mining activities plus land used by plants, offices and equipment. Land use calculations were modified in 2021 to include a greater portion of the land used by TransAlta including all surrounding land and land leased to our customers. As a result, minor adjustments were made to historical 2020 and 2019 data for land used by facilities, offices and equipment.
18. Environmental incidents are separated into two categories: significant environmental incidents (internally defined) and regulatory non-compliance environmental incidents (aligned to GRI 307-1). We define significant environmental incidents as an incident that resulted in an impact to the environment with low level damage to the ecosystem that is reversible within one to three years or mortalities of less than 0.2 per cent of a given species when compared to the overall population. Our internal definition of significant environmental incidents in 2020 and 2019 included all incidents involving mortality of a single listed species as reflected in our 2020 and 2019 reported values. We have updated our internal definition to reflect what we deem to be a more appropriate way to measure a significant environmental event related to species mortalities; the internal definition now takes into consideration mortality impacts to the species in relation to overall species population. We define regulatory non-compliance environmental incidents as violations or non-compliance to regulations or exceedance of limits in company operating approvals that result in enforcement action including fines or stop work orders that suspend overall facility or site operations, 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.
19. 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.
20. 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 Company.
21. In 2022, TransAlta had approximately 376 unionized workers working primarily in our operational business units.
22. 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.
23. Health and safety enforcement actions are a violation of or non-compliance with regulations or exceedance of limits in company operating approvals that result in enforcement action including stop work orders, fines or suspension of operating approvals.
24. Lost-time injuries (LTIs) are injuries that resulted in the worker being away from work beyond the day of the injury.
25. Medical aids (MAs) are injuries that resulted in medical treatment beyond first aid.
26. Restricted work injuries (RWIs) are injuries that resulted in the worker being unable to perform all normally scheduled and assigned work activities.
27. Exposure hours are total hours worked by all TransAlta employees and contractors, and include full-time, part-time, direct, contract, executive, labour, salary, hourly and seasonal employees in all locations, but exclude prime contractors. Exposure hours have been rounded to the nearest thousand.
28. Total Recordable Injury Frequency (TRIF) measures restricted work, medical aid and lost-time injuries per 200,000 hours worked.
29. 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 Management of TransAlta Corporation ("TransAlta")

Scope

We have been engaged by TransAlta Corporation (the "Company", or "TransAlta") to perform a 'limited assurance engagement,' as defined by International Standards on Assurance Engagements, hereafter referred to as the engagement, to report on TransAlta's performance indicators detailed in the accompanying schedule (the "Subject Matter") for the year ended December 31, 2022, contained in TransAlta's 2022 Annual Integrated Report (the "Report").

Other than as described in the preceding paragraph, which sets out the scope of our engagement, this engagement did not include performing assurance procedures on the remaining information included in the Report, and accordingly, we do not express a conclusion on this information.

Criteria Applied by TransAlta

In preparing the Subject Matter, TransAlta applied relevant guidance contained within the Sustainability Accounting Standards Board ("SASB") Standards, Global Reporting Initiative ("GRI") Sustainability Reporting Standards, and internally developed criteria, as detailed in the accompanying Schedule, collectively referred to herein as (the "Criteria"). The internally developed Criteria were specifically designed for the preparation of the Report. As a result, the Subject Matter 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 the evidence we have obtained.

We conducted our engagement in accordance with the International Standard for Assurance Engagements ("ISAE") 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information ("ISAE 3000") and ISAE 3410, Assurance Engagements on Greenhouse Gas Statements ("ISAE 3410"). These standards require 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 conclusion.

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 behaviour.

EY 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 enquiries, primarily of persons responsible for preparing the Subject Matter and related information, and applying analytical and other appropriate procedures.

Our procedures included:

- Conducting interviews with relevant personnel to obtain an understanding of the reporting processes;
- Inquiries of relevant personnel who are responsible for the Subject Matter including, where relevant, observing and inspecting systems and processes for data aggregation and reporting in accordance with the Criteria;
- Assessing the accuracy of data, through analytical procedures and limited reperformance of calculations, where applicable, and tested, on a limited sample basis, underlying source information to support completeness and accuracy of the Subject Matter; and
- Reviewing presentation and disclosure of the Subject Matter in the Report

We also performed such other procedures as we considered necessary in the circumstances.

Inherent Limitations

The Greenhouse Gas ("GHG") quantification process is subject to scientific uncertainty, which arises because of incomplete scientific knowledge about the measurement of GHGs. Additionally, GHG procedures are subject to estimation (or measurement) uncertainty resulting from the measurement and calculation processes used to quantify emissions within the bounds of existing scientific knowledge.

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.

Conclusion

Based on our procedures and the evidence obtained, nothing has come to our attention that causes us to believe that the Subject Matter for the year ended December 31, 2022, is not prepared, in all material respects, in accordance with the Criteria.

Ernst & Young LLP

Chartered Professional Accountants

Ernst & Young LLP
February 22, 2023
Calgary, Canada

Schedule

Our limited assurance engagement was performed on the following Subject Matter for the year ended December 31, 2022:

Performance Indicator	Criteria	Value	Unit of Measure
Greenhouse Gas Emissions			
Total (Scope 1 and Scope 2) greenhouse gas emissions	SASB IF-EU-110a.1	**10,248,000**	tonnes CO_2e
Greenhouse gas emission intensity	GRI 305-4	**0.4**	tonnes CO_2e /MWh
Air Emissions			
Total sulphur dioxide emissions	SASB IF-EU-120a.1	**1,000**	tonnes
Sulphur dioxide emission intensity	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**0.05**	kg/MWh
Total nitrogen oxide emissions	SASB IF-EU-120a.1	**11,000**	tonnes
Nitrogen oxide emission intensity	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**0.43**	kg/MWh
Total particulate matter emissions	SASB IF-EU-120a.1	**400**	tonnes
Particulate matter emission intensity	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**0.02**	kg/MWh
Total mercury emissions	SASB IF-EU-120a.1	**20**	kg
Mercury emission intensity	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**0.77**	mg/MWh
Water Management			
Water withdrawn – all sources	SASB IF-EU-140a.1	**230**	million m^3
Water discharge – all sources	SASB IF-EU-140a.1	**210**	million m^3
Water consumption	SASB IF-EU-140a.1	**20**	million m^3
Water consumption intensity	SASB IF-EU-140a.1	**1.03**	m^3/MWh
Waste Management			
Non-hazardous			

Performance Indicator	Criteria	Value	Unit of Measure
Landfill	GRI 306-2	**1,800**	tonnes
Landfill	GRI 306-2	**76,200**	litres
Ash disposal: mine	GRI 306-2	**2,910**	tonnes
Ash disposal: lagoon	GRI 306-2	**0**	tonnes
Recycled	GRI 306-2	**1,600**	tonnes
Recycled	GRI 306-2	**2,103,000**	litres
Reuse	GRI 306-2	**151,000**	tonnes
Storage	GRI 306-2	**26,000**	tonnes
Hazardous			
Landfill	GRI 306-2	**80**	tonnes
Landfill	GRI 306-2	**52,000**	litres
Recycled	GRI 306-2	**0**	tonnes
Recycled	GRI 306-2	**21,019,000**	litres
Land Use and Reclamation			
Land used in mining activities – disturbed	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**12,600**	cumulative hectares
Land used in mining activities – reclaimed	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**4,800**	cumulative hectares
Land reclamation (used in mining activities)	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**38**	% of land disturbed
Land used in mining activities: disturbed minus reclaimed	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**7,800**	hectares
Land used by facilities, offices and equipment	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**5,000**	hectares
Total land use	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**12,700**	cumulative hectares
Environmental Incidents			
Total significant environmental incidents	Internally developed criteria as described in the footnotes to the Sustainability Performance Indicators of the Report	**1**	Number
Health and Safety			
Employee & contractor fatalities	SASB IF-EU-320a.1(1)	**0**	Number
Lost-time injury (LTI) incidents	SASB IF-EU-320a.1(1)	**0**	Number
Medical aid (MA) incidents	SASB IF-EU-320a.1(1)	**6**	Number
Restricted work injury (RWI) incidents	SASB IF-EU-320a.1(1)	**0**	Number
Total recordable injuries to employees & contractors	SASB IF-EU-320a.1(1)	**6**	Number
Total Recordable Injury Frequency (TRIF) (employees and contractors)	SASB IF-EU-320a.1(1)	**0.39**	Rate

(1) Other criteria, included in the SASB Disclosure IF-EU-320a.1 Section 3, near miss frequency rate (NMFR) is excluded from the scope of our limited assurance engagement.

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
February 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 December 31, 1971, adjusted for stock splits, is $4.54 per share.
(1) The adjusted cost base for shares held on January 31, 1988, was reduced by $0.75 per share following the February 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 2022

Payment Date	Record Date	Ex-Dividend Date	Dividend
April 1, 2022	March 1, 2022	February 28, 2022	$0.050
July 1, 2022	June 1, 2022	May 31, 2022	$0.050
October 1, 2022	September 1, 2022	August 31, 2022	$0.050
January 1, 2023	December 1, 2022	November 30, 2022	$0.055
April 1, 2023	March 1, 2023	February 28, 2023	$0.055

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 Company.

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 $0.71924 per share from and including March 31, 2021, to, but excluding, March 31, 2026.

Series B: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including March 31, 2021, to, but excluding, March 31, 2026.

Series C: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.46352 per share from and including June 30, 2022, to, but excluding, June 30, 2027.

Series D: Floating cumulative preferential cash dividends are paid quarterly when declared by the Board from and including June 30, 2022, to, but excluding, June 30, 2027.

Series E: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.72352 per share from and including September 30, 2022, to, but excluding, September 30, 2027.

Series G: Fixed cumulative preferential cash dividends are paid quarterly when declared by the Board at the annual rate of $1.247 per share from and including September 30, 2019, to, but excluding, September 30, 2024.

Preferred Share Dividends Declared in 2022

Series A			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
March 31, 2022	March 1, 2022	February 28, 2022	$0.17981
June 30, 2022	June 1, 2022	May 31, 2022	$0.17981
September 30, 2022	September 1, 2022	August 31, 2022	$0.17981
December 31, 2022	December 1, 2022	November 30, 2022	$0.17981
March 31, 2023	March 1, 2023	February 28, 2023	$0.17981
Series B			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
March 31, 2022	March 1, 2022	February 28, 2022	$0.13309
June 30, 2022	June 1, 2022	May 31, 2022	$0.16505
September 30, 2022	September 1, 2022	August 31, 2022	$0.22099
December 31, 2022	December 1, 2022	November 30, 2022	$0.33700
March 31, 2023	March 1, 2023	February 28, 2023	$0.37991
Series C			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
March 31, 2022	March 1, 2022	February 28, 2022	$0.25169
June 30, 2022	June 1, 2022	May 31, 2022	$0.25169
September 30, 2022	September 1, 2022	August 31, 2022	$0.36588
December 31, 2022	December 1, 2022	November 30, 2022	$0.36588
March 31, 2023	March 1, 2023	February 28, 2023	$0.36588
Series D			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
June 30, 2022	June 1, 2022	May 31, 2022	$0.25169
September 30, 2022	September 1, 2022	August 31, 2022	$0.28841
December 31, 2022	December 1, 2022	November 30, 2022	$0.40442
March 31, 2023	March 1, 2023	February 28, 2023	$0.45578
Series E			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
March 31, 2022	March 1, 2022	February 28, 2022	$0.32463
June 30, 2022	June 1, 2022	May 31, 2022	$0.32463
September 30, 2022	September 1, 2022	August 31, 2022	$0.32463
December 31, 2022	December 1, 2022	November 30, 2022	$0.43088
March 31, 2023	March 1, 2023	February 28, 2023	$0.43088
Series G			
Payment Date	**Record Date**	**Ex-Dividend Date**	**Dividend**
March 31, 2022	March 1, 2022	February 28, 2022	$0.31175
June 30, 2022	June 1, 2022	May 31, 2022	$0.31175
September 30, 2022	September 1, 2022	August 31, 2022	$0.31175
December 31, 2022	December 1, 2022	November 30, 2022	$0.31175
March 31, 2023	March 1, 2023	February 28, 2023	$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 has also declared dividends on the Series I Preferred Shares, which are held 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 12:30 p.m., Mountain standard time, on Friday, April 28, 2023.

Transfer Agent

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Website:
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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.G, TA.PR.H, TA.PR.J

Additional Information

Requests can be directed to:

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investor_relations@transalta.com

Website
www.transalta.com

Shareholder Highlights

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

Year ended December 31 ($)	13	14	15	16	17	18	19	20	21	22
TransAlta	100	83	42	66	67	51	87	93	137	120
S&P/TSX	100	111	101	123	134	122	150	158	198	186

This chart compares what $100 invested in TransAlta and the S&P/TSX Composite Index at the end of 2013 would be worth today, assuming the reinvestment of all dividends.

Source: FactSet

Ten-Year Market Value vs. Book Value

Year ended December 31 ($ per share)	13	14	15	16	17	18	19	20	21	22
Market Value	13.48	10.52	4.91	7.43	7.45	5.59	9.28	9.67	14.05	12.11
Book Value	7.92	8.52	8.52	8.92	8.28	7.16	7.14	5.13	2.37	0.62

Data is from 2013 onwards.

Source: FactSet and TransAlta

Monthly Volume and Market Prices

2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Volume (millions)	15	12	21	14	17	18	13	19	20	14	18	13
TSX closing price *($ per share)*	13.79	12.87	12.94	13.78	14.42	14.69	14.66	12.33	12.21	12.00	12.56	12.11

Source: FactSet

Return on Common Shareholders' Equity

(%)	13	14	15	16	17	18	19	20	21	22
ROE	(3.2)	6.3	(1.2)	5.4	(10.0)	(15.8)	3.3	(30.3)	(116.6)	1.0

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 **1.800.40.5308** (Australia)
Internet portal: **transalta.com/ethics-helpline**
Email: **ethics_helpline@transalta.com**

Any communications to the Board of Directors may also be sent to **corporate_secretary@transalta.com**.

TransAlta Corporate Officers

John Kousinioris
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and Chief Financial Officer
President of TransAlta Renewables Inc.

Jane Fedoretz
Executive Vice President, People, Talent and Transformation

Kerry O'Reilly Wilks
Executive Vice President, Legal, Commercial and External Affairs

Chris Fralick
Executive Vice President, Generation

Blain van Melle
Executive Vice President, Alberta Business

Aron Willis
Executive Vice President, Growth

Shasta Kadonaga
Senior Vice President, Shared Services

Brent Ward
Senior Vice President, M&A, Strategy and Treasurer
Chief Financial Officer of TransAlta Renewables Inc.

Michelle Cameron
Vice President and Corporate Controller

Scott Jeffers
Vice President and Corporate Secretary

Glossary of Key Terms

Adjusted Availability
Availability is adjusted when economic conditions exist, such that planned routine and major maintenance activities are scheduled to minimize expenditures. In high price environments, actual outage schedules would change to accelerate the generating unit's return to service.

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 Company's hydroelectric assets owned through a wholly owned subsidiary, TA Alberta Hydro LP. These assets are located in Alberta and consist of the Barrier, Bearspaw, Bighorn, Brazeau, Cascade, Ghost, Horseshoe, Interlakes, Kananaskis, Pocaterra, Rundle, Spray and Three Sisters 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.

Alberta Thermal
The business segment previously disclosed as Canadian Coal has been renamed to reflect the ongoing conversion of the boilers to burn gas in place of coal. The segment includes the legacy and converted generating units at our Sundance and Keephills sites and includes the Highvale mine.

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 (AUC).

Availability
A measure of time, expressed as a percentage of continuous operation - 24 hours a day, 365 days a year - that a generating unit is capable of generating electricity, regardless of whether or not it is actually generating electricity.

Balancing Pool
The Balancing Pool was established in 1999 by the Government of Alberta to help manage the transition to competition in Alberta's electric industry. Their current obligations and responsibilities are governed by the Electric Utilities Act (effective June 1, 2003) and the Balancing Pool Regulation. For more information go to www.balancingpool.ca.

Boiler
A device for generating steam for power, processing or heating purposes, or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes of the boiler shell.

Capacity
Generation equipment's rated, continuous load-carrying ability, expressed in megawatts.

Carbon Tax
Sets a carbon price per tonne of GHG emissions related to transportation fuels, heating fuels and other small emission sources.

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.

Centralia
The business segment previously disclosed as US Coal has been renamed to reflect the sole asset.

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.

Derate
To lower the rated electrical capability of a power generating facility or 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 Company 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 Company 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.

Dispatch Optimization
Purchasing power to fulfil contractual obligations, when economical.

Emissions Performance Standards ("EPS")
Under the Government of Ontario, emission performance standards establish greenhouse gas (GHG) emissions limits for covered facilities.

Environmental Management Systems (EMS)
A set of processes and practices that enable an organization to reduce its environmental impacts and increase its operating efficiency.

EPCs
Emission Performance Credits.

Force Majeure
Literally means “greater force.” A clause in a contract that excuses 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 Company through its operations (cash from operations) minus the funds used by the Company for the purchase, improvement or maintenance of the long-term assets to improve the efficiency or capacity of the Company (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 Company believes are not representative of ongoing cash flows from operations.

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.

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.

Greenhouse Gas (GHG)
A gas that has the potential to retain heat in the atmosphere, including water vapour, carbon dioxide, methane, nitrous oxide, hydrofluorocarbons and perfluorocarbons.

Heat Rate
A measure of conversion, expressed as British thermal units per Megawatt hour, of the amount of thermal energy required to generate electrical energy.

ICFR
Internal control over financial reporting.

IFRS
International Financial Reporting Standards.

KH Bonds
The Kent Hills Wind LP ("KHLP") non-recourse project bonds secured by, among other things, the Kent Hills 1, 2 and 3 wind facilities.

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.

NCIB
Normal Course Issuer Bid.

OM&A
Operations, maintenance and administration costs.

Other Hydro Assets
The Company's hydroelectric assets located in British Columbia and Ontario and assets owned by TransAlta Renewables, which include the Taylor, Belly River, Waterton, St. Mary, Upper Mamquam, Pingston, Bone Creek, Akolkolex, Ragged Chute, Misema, Galetta, Appleton and Moose Rapids facilities.

Pioneer Pipeline
The Pioneer gas pipeline jointly owned and operated by TransAlta and Tidewater Midstream and Infrastructure Ltd.

Planned Outage
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.

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.

PP&E
Property, plant and equipment.

Renewable Energy Credits (REC)
All right, title, interest and benefit in and to any credit, reduction right, offset, allocated pollution right, emission reduction allowance, renewable attribute or other proprietary or contractual right, whether or not tradable, resulting from the actual or assumed displacement or reduction of emissions, or other environmental characteristic, from the production of one MWh of electrical energy from a facility utilizing certified renewable energy technology.

Renewable Power
Power generated from renewable terrestrial mechanisms including wind, geothermal, solar and biomass with regeneration.

Spark Spread
A measure of gross margin per megawatt (sales price less cost of natural gas).

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.

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.

Unplanned Outage
The shutdown of a generating unit due to an unanticipated breakdown.

Value at Risk (VaR)
A measure used to manage exposure to market risk from commodity risk management activities.

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