TransAlta™

TransAlta Corporation

Consolidated Financial Statements

December 31, 2021

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 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 23, 2022

Management's Annual Report on Internal Control Over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

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

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

In accordance with the provisions of NI 52-109 and consistent with U.S. Securities and Exchange Commission guidance, the scope of the evaluation did not include internal controls over financial reporting of North Carolina Solar, which the Company acquired on Nov. 5, 2021. North Carolina Solar was excluded from management's evaluation of the effectiveness of the Company's internal control over financial reporting as at Dec. 31, 2021, due to the proximity of the acquisition to year-end. Further details related to the acquisition are disclosed in Note 4 to the Company's Consolidated Financial Statements for the year ended Dec. 31, 2021. Included in the 2021 Consolidated Financial Statements of TransAlta for North Carolina Solar is 2 per cent and 5 per cent of the Company's total and net assets, respectively, as at Dec. 31, 2021.

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 2021 Consolidated Financial Statements of TransAlta for joint operations and equity accounted investments are 4 per cent and 10 per cent of the Company's total and net assets, respectively, as of Dec. 31, 2021, and 8 per cent of the Company's revenues for the year then ended.

Changes in Internal Controls over Financial Reporting

The Company's internal controls over financial reporting commencing Nov. 5, 2021, include controls designed to result in complete and accurate consolidation of North Carolina Solar's results. Other than the North Carolina Solar acquisition, 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 are 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, 2021, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2021, 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
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and
Chief Financial Officer

February 23, 2022

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, 2021, 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, 2021, 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 2021 consolidated financial statements of the Company and constituted 4% and 10% of total and net assets, respectively, as of December 31, 2021, and 8% 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.

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 North Carolina Solar, which is included in the 2021 consolidated financial statements of the Company and constituted 2% and 5% of total and net assets, respectively, as of December 31, 2021. 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 North Carolina Solar.

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, 2021 and 2020, and the related consolidated statements of earnings (loss), comprehensive earnings (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2021, and the related notes and our report dated February 23, 2022 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.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
February 23, 2022

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, 2021 and 2020, the related consolidated statements of earnings (loss), comprehensive earnings (loss), changes in equity and cash flows, for each of the three years in the period ended December 31, 2021, 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, 2021 and 2020, and the financial performance and its cash flows for each of the three years in the period ended December 31, 2021, 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, 2021, 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 23, 2022 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 and Solar segment and Goodwill related to the Wind and Solar segment

Description of the Matter	As disclosed in notes 2(G), 2(H), 2(P)(I), 7, 18 and 21 of the consolidated financial statements, the Company owns significant Wind and Solar 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 and Solar segment was $175 million and the carrying value of long-lived assets in the Wind and Solar segment consisted of property, plant & equipment of $2,304 million, right-of-use assets of $64 million and intangible assets of $147 million as at December 31, 2021. Determining the recoverable amounts for the Wind and Solar segment for the purposes of the goodwill impairment test and of certain CGUs in the Wind and Solar segment with indicators of impairment ("Wind and Solar 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 generation profiles, commodity prices, cost estimates, 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 and Solar segment and the Wind and Solar 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 and Solar segment and the Wind and Solar 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 power generation data to evaluate future generation forecasts. We assessed the historical accuracy of management's forecasts by comparing them with actual results and performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of the recoverable amount. We evaluated the Company's determination of future commodity prices by comparing them to externally available third-party future commodity price estimates. We also involved our internal valuation specialist to assist in our evaluation of the discount rates, which involved benchmarking the inputs against available market data.

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(P)(IV), 15 and 25 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, 2021 the fair value of the Company's derivative financial instruments classified as level III was $159 million net risk management assets.

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

How We Addressed the Matter in Our Audit

We obtained an understanding of the 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 valuation adjustments, and liquidity assumptions to third-party data as well as comparing terms such as volumes and timing to executed commodity contracts. We compared the unit availability and demand profile assumptions to historical information. We performed a sensitivity analysis to evaluate the assumptions that were most significant to the determination of level III fair value. For a sample of level III derivative instruments, we involved our internal valuation specialist to assist in our evaluation of the appropriateness of the discount rates by evaluating the key assumptions and methodologies.

Ernst & Young LLP

Chartered Professional Accountants
We have served as auditors of TransAlta Corporation and its predecessor entities since 1947.
Calgary, Canada
February 23, 2022

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2021**	2020	2019
Revenues (Note 5)	**2,721**	2,101	2,347
Fuel and purchased power (Note 6)	**1,054**	805	881
Carbon compliance	**178**	163	205
Gross margin	**1,489**	1,133	1,261
Operations, maintenance and administration (Note 6)	**511**	472	475
Depreciation and amortization	**529**	654	590
Asset impairment charge (Note 7)	**648**	84	25
Gain on termination of Keephills 3 coal rights contract (Note 18)	**—**	—	(88)
Taxes, other than income taxes	**32**	33	29
Termination of Sundance B and C PPAs	**—**	—	(56)
Net other operating loss (income) (Note 9)	**8**	(11)	(49)
Operating income (loss)	**(239)**	(99)	335
Equity income (Note 10)	**9**	1	—
Finance lease income	**25**	7	6
Net interest expense (Note 11)	**(245)**	(238)	(179)
Foreign exchange gain (loss)	**16**	17	(15)
Gain on sale of assets and other (Note 4 and 18)	**54**	9	46
Earnings (loss) before income taxes	**(380)**	(303)	193
Income tax expense (recovery) (Note 12)	**45**	(50)	17
Net earnings (loss)	**(425)**	(253)	176
Net earnings (loss) attributable to:			
TransAlta shareholders	**(537)**	(287)	82
Non-controlling interests (Note 13)	**112**	34	94
	(425)	(253)	176
Net earnings (loss) attributable to TransAlta shareholders	**(537)**	(287)	82
Preferred share dividends (Note 28)	**39**	49	30
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
Weighted average number of common shares outstanding in the year *(millions)*	**271**	275	283
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 27)	**(2.13)**	(1.22)	0.18

See accompanying notes.

Consolidated Statements of Comprehensive Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020	2019
Net earnings (loss)	**(425)**	(253)	176
Other comprehensive loss			
Net actuarial gains (loss) on defined benefit plans, net of tax[(1)]	**37**	(11)	(26)
Losses on derivatives designated as cash flow hedges, net of tax	**—**	(1)	—
Total items that will not be reclassified subsequently to net earnings	**37**	(12)	(26)
Losses on translating net assets of foreign operations, net of tax	**(14)**	(11)	(59)
Gains on financial instruments designated as hedges of foreign operations, net of tax	**—**	11	21
Gains (losses) on derivatives designated as cash flow hedges, net of tax[(2)]	**(200)**	20	61
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax[(3)]	**(8)**	(110)	(42)
Total items that will be reclassified subsequently to net earnings	**(222)**	(90)	(19)
Other comprehensive loss	**(185)**	(102)	(45)
Total comprehensive earnings (loss)	**(610)**	(355)	131
Total comprehensive earnings (loss) attributable to:			
TransAlta shareholders	**(693)**	(439)	54
Non-controlling interests (Note 13)	**83**	84	77
	(610)	(355)	131

(1) Net of income tax expense of $11 million for the year ended Dec. 31, 2021 (2020 — $3 million recovery, 2019 — $7 million recovery).
(2) Net of income tax recovery of $55 million for the year ended Dec. 31, 2021 (2020 —$8 million expense, 2019 — $16 million expense).
(3) Net of reclassification of income tax recovery of $2 million for the year ended Dec. 31, 2021 (2020 —$31 million recovery, 2019 — $10 million recovery).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020
Cash and cash equivalents	**947**	703
Restricted cash (Note 24)	**70**	71
Trade and other receivables (Note 14)	**651**	583
Prepaid expenses	**29**	31
Risk management assets (Note 15 and 16)	**308**	171
Inventory (Note 17)	**167**	238
Assets held for sale (Note 4 and 18)	**25**	105
	2,197	1,902
Investments (Note 10)	**105**	100
Long-term portion of finance lease receivables (Note 8)	**185**	228
Risk management assets (Note 15 and 16)	**399**	521
Property, plant and equipment (Note 18)		
Cost	**13,389**	13,398
Accumulated depreciation	**(8,069)**	(7,576)
	5,320	5,822
Right-of-use assets (Note 19)	**95**	141
Intangible assets (Note 20)	**256**	313
Goodwill (Note 21)	**463**	463
Deferred income tax assets (Note 12)	**64**	51
Other assets (Note 22)	**142**	206
Total assets	**9,226**	9,747
Accounts payable and accrued liabilities	**689**	599
Current portion of decommissioning and other provisions (Note 23)	**48**	59
Risk management liabilities (Note 15 and 16)	**261**	94
Current portion of contract liabilities (Note 5)	**19**	1
Income taxes payable	**8**	18
Dividends payable (Note 27 and 28)	**62**	59
Current portion of long-term debt and lease liabilities (Note 24)	**844**	105
	1,931	935
Credit facilities, long-term debt and lease liabilities (Note 24)	**2,423**	3,256
Exchangeable securities (Note 25)	**735**	730
Decommissioning and other provisions (Note 23)	**779**	614
Deferred income tax liabilities (Note 12)	**354**	396
Risk management liabilities (Note 15 and 16)	**145**	68
Contract liabilities (Note 5)	**13**	14
Defined benefit obligation and other long-term liabilities (Note 26)	**253**	298
Equity		
Common shares (Note 27)	**2,901**	2,896
Preferred shares (Note 28)	**942**	942
Contributed surplus	**46**	38
Deficit	**(2,453)**	(1,826)
Accumulated other comprehensive income (Note 29)	**146**	302
Equity attributable to shareholders	**1,582**	2,352
Non-controlling interests (Note 13)	**1,011**	1,084
Total equity	**2,593**	3,436
Total liabilities and equity	**9,226**	9,747

Commitments and contingencies (Note 36)

On behalf of the Board:

John P. Dielwart
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2019	2,978	942	42	(1,455)	454	2,961	1,101	4,062
Net earnings (loss)	—	—	—	(287)	—	(287)	34	(253)
Other comprehensive earnings (loss):								
Net losses on derivatives designated as cash flow hedges, net of tax	—	—	—	—	(91)	(91)	—	(91)
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(11)	(11)	—	(11)
Intercompany FVOCI investments	—	—	—	—	(50)	(50)	50	—
Total comprehensive earnings (loss)				(287)	(152)	(439)	84	(355)
Common share dividends	—	—	—	(58)	—	(58)	—	(58)
Preferred share dividends	—	—	—	(49)	—	(49)	—	(49)
Shares purchased under NCIB	(79)	—	—	18	—	(61)	—	(61)
Changes in non-controlling interests in TransAlta Renewables (Note 13)	—	—	—	5	—	5	15	20
Effect of share-based payment plans	(3)	—	(4)	—	—	(7)	—	(7)
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(116)	(116)
Balance, Dec. 31, 2020	2,896	942	38	(1,826)	302	2,352	1,084	3,436
Net earnings (loss)	**—**	**—**	**—**	**(537)**	**—**	**(537)**	**112**	**(425)**
Other comprehensive earnings (loss):								
Net losses on translating net assets of foreign operations, net of hedges and tax	**—**	**—**	**—**	**—**	**(14)**	**(14)**	**—**	**(14)**
Net gains (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 FVOCI investments	**—**	**—**	**—**	**—**	**29**	**29**	**(29)**	**—**
Total comprehensive earnings (loss)				**(537)**	**(156)**	**(693)**	**83**	**(610)**
Common share dividends	**—**	**—**	**—**	**(51)**	**—**	**(51)**	**—**	**(51)**
Preferred share dividends	**—**	**—**	**—**	**(39)**	**—**	**(39)**	**—**	**(39)**
Effect of share-based payment plans (Note 30)	**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**

(1) Refer to Note 29 for details on components of, and changes in, accumulated other comprehensive earnings (loss).
See accompanying notes.

Consolidated Statements of Cash Flows

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2021**	2020	2019
Operating activities			
Net earnings (loss)	**(425)**	(253)	176
Depreciation and amortization (Note 18 and 37)	**719**	798	709
Net gain on sale of assets	**(54)**	(9)	(45)
Accretion of provisions (Note 23)	**32**	30	23
Decommissioning and restoration costs settled (Note 23)	**(18)**	(18)	(34)
Deferred income tax recovery (Note 12)	**(11)**	(85)	(18)
Unrealized (gain) loss from risk management activities	**(34)**	42	(32)
Unrealized foreign exchange (gain) loss	**(24)**	1	13
Provisions	**(41)**	9	13
Asset impairment (Note 7)	**648**	84	25
Equity income, net of distributions from investments (Note 10)	**(5)**	(1)	—
Other non-cash items	**40**	15	(102)
Cash flow from operations before changes in working capital	**827**	613	728
Change in non-cash operating working capital balances (Note 33)	**174**	89	121
Cash flow from operating activities	**1,001**	702	849
Investing activities			
Additions to property, plant and equipment (Note 18 and 37)	**(480)**	(486)	(417)
Additions to intangible assets (Note 20 and 37)	**(9)**	(14)	(14)
Restricted cash (Note 24)	**(1)**	(39)	34
Loan receivable (Note 22)	**(3)**	(5)	(10)
Acquisitions, net of cash acquired (Note 4)	**(120)**	(32)	(117)
Acquisition of investments (Note 10)	**—**	(102)	—
Investment in the Pioneer Pipeline	**—**	—	(83)
Proceeds on sale of Pioneer Pipeline (Note 4)	**128**	—	—
Proceeds on sale of property, plant and equipment	**39**	6	13
Realized gains (losses) on financial instruments	**(6)**	2	3
Decrease in finance lease receivable	**41**	17	24
Other	**(16)**	(12)	23
Change in non-cash investing working capital balances	**(45)**	(22)	32
Cash flow used in investing activities	**(472)**	(687)	(512)
Financing activities			
Net decrease in borrowings under credit facilities (Note 24 and 33)	**(114)**	(106)	(119)
Repayment of long-term debt (Note 24 and 33)	**(92)**	(489)	(96)
Issuance of long-term debt (Note 24)	**173**	753	166
Issuance of exchangeable securities (Note 25)	**—**	400	350
Dividends paid on common shares (Note 27)	**(48)**	(47)	(45)
Dividends paid on preferred shares (Note 28)	**(39)**	(39)	(40)
Repurchase of common shares under NCIB (Note 27)	**(4)**	(57)	(68)
Proceeds on issuance of common shares	**8**	—	—
Realized gains on financial instruments	**3**	3	—
Distributions paid to subsidiaries' non-controlling interests (Note 13)	**(156)**	(97)	(106)
Decrease in lease liabilities (Note 24 and 33)	**(8)**	(25)	(21)
Financing fees and other	**(4)**	(11)	(35)
Change in non-cash financing working capital balances	**(1)**	(13)	—
Cash flow from (used in) financing activities	**(282)**	272	(14)
Cash flow from operating, investing, and financing activities	**247**	287	323
Effect of translation on foreign currency cash	**(3)**	5	(1)
Increase in cash and cash equivalents	**244**	292	322
Cash and cash equivalents, beginning of year	**703**	411	89
Cash and cash equivalents, end of year	**947**	703	411
Cash taxes paid	**57**	36	35
Cash interest paid	**220**	201	185

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

During the fourth quarter of 2021, the Company realigned its current operating segments to better reflect a change in how TransAlta's President and Chief Executive Officer (the chief operating decision maker) ("CODM") reviews financial information in order to allocate resources and assess performance. The primary changes are the elimination of the Alberta Thermal and the Centralia segments, and the reorganization of the North American Gas and Australia Gas segments into a new "Gas" segment. The Alberta Thermal facilities that have been converted to gas have been included in the Gas segment. The remaining assets previously included in Alberta Thermal, including the mining assets and those facilities not converted to gas and the remaining Centralia unit, are included in a new "Energy Transition" segment. No changes were made to the Hydro and Wind and Solar segments. This change better aligns with the Company's long-term strategy and reflects its Clean Electricity Growth Plan.

The four generation segments of the Company are as follows: Hydro, Wind and Solar, Gas, and Energy Transition. Previously, the six generation segments were as follows: Hydro, Wind and Solar, North American Gas, Australian Gas, Alberta Thermal, and Centralia. The Company directly or indirectly owns and operates hydro, wind and solar, natural-gas-fired and coal-fired facilities, related mining operations and natural gas pipeline operations in Canada, the United States ("US") and Australia. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment, LLC. Revenues are derived from the availability and production of electricity and steam as well as ancillary services.

Comparative segmented results for 2020 and 2019 have been restated to align with the 2021 operating segments.

II. Energy Marketing Segment

The Energy Marketing segment derives revenue and earnings from the wholesale trading of electricity and other energy-related commodities and derivatives. No change was made to the Energy Marketing segment.

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

III. Corporate and Other Segment

The Corporate and Other segment includes the 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. Since 2020, the Corporate and Other segment also includes the investment in EMG International, LLC ("EMG"), a wastewater treatment processing company.

B. Basis of Preparation

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

The consolidated financial statements have been prepared on a historical cost basis except for financial instruments, 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. 23, 2022.

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 the accounting policies disclosed in accordance with the amendments to IAS 1 to disclose the material accounting policy information rather than significant 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. Revenue is measured based on the transaction price specified in a contract with a customer. Revenue is recognized when control of the good or services is transferred to the customer. For certain contracts, revenue may be recognized at the invoiced amount, as permitted using the invoice practical expedient, if such amount corresponds directly with the 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 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, 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 (i.e., 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 (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Environmental attributes	Environmental attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for environmental attributes in conjunction with the purchase of power, in which case the customer pays for the attributes in the month subsequent to the delivery of the power. Alternatively, customers pay upon delivery of the environmental attributes. Obligations to deliver environmental attributes are satisfied at a point in time, generally upon delivery of the item.
Generation byproducts	Generation byproducts refers to the sale of byproducts from the use of coal in the Company's Canadian and US coal operations, and the sale of coal to third parties. Obligations to deliver byproducts are satisfied at a point in time, generally upon delivery of the item. Payments are received upon satisfaction of delivery of the byproducts.

A contract liability is recorded when the 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) are comprised of 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 ("PPA"). Contracts for differences is a financial contract whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh. A virtual PPA is where 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 ("FVOCI").

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

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

Funds received under tax equity investment arrangements are classified as long-term debt. These arrangements are used in the US where project investors acquire an equity investment in the project entity and in return for their investment, are allocated substantially all of the earnings, cash flows and tax benefits (such as production tax credits, investment tax credits, accelerated tax depreciation, as applicable) until they have achieved the agreed upon target rate of return. Once achieved, the arrangements flip, with the 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 earnings ("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 earnings ("AOCI") must remain in AOCI if the hedged future cash flows are still expected to occur. Otherwise, the amount will be immediately reclassified to net earnings as a reclassification adjustment. After discontinuation, once the hedged cash flow occurs, any amount remaining in AOCI must be accounted for depending on the nature of the underlying transaction.

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

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

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

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

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

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

IV. Emission Credits and Allowances
Emission credits and allowances are recorded as inventory at cost. Those purchased for use by the 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 assets if it is probable that future economic benefits will be realized and the cost of the item can be measured reliably. The cost of major spare parts is capitalized and classified as PP&E, as these items can only be used in connection with an item of PP&E.

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

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

An item of PP&E or a component is derecognized upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition is included in net earnings when the asset is derecognized. The estimate of the useful life of each component of PP&E is based on current facts and past experience, and takes into consideration existing long-term sales agreements and contracts, current and forecasted demand, and the potential for technological obsolescence. The useful life is used to estimate the rate at which the component of PP&E is depreciated. PP&E assets are subject to depreciation when the asset is considered to be available for use, which is typically upon commencement of commercial operations. Capital spares that are designated as critical for uninterrupted operation in a particular facility are depreciated over the life of that facility, even if the item is not in service. Other capital spares begin to be depreciated when the item is put into service. Each significant component of an item of PP&E is depreciated to its residual value over its estimated useful life, generally using straight-line or unit-of-production methods. Estimated useful lives, residual values and depreciation methods are reviewed annually and are subject to revision based on new or additional information. The effect of a change in useful life, residual value or depreciation method is accounted for prospectively.

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

Hydro generation	2-51 years
Wind generation	2-30 years
Gas generation	2-36 years
Energy Transition	2-16 years
Capital spares and other	2-51 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 and fuel and purchased power in the Consolidated Statements of Earnings (Loss).

Amortization commences when the intangible asset is available for use and is computed on a straight-line basis over the intangible asset's estimated useful life. 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	2-7 years
Power sale contracts	1-19 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 pro-rated based on service. The net interest cost is determined by applying the discount rate to the net defined benefit liability. The discount rate used to determine the present value of the defined benefit obligation, and the net interest cost, is determined by reference to market yields at the end of the reporting period on high-quality corporate bonds with terms and currencies that match the estimated terms and currencies of the benefit obligations. Remeasurements, which include actuarial gains and losses and the return on plan assets (excluding net interest), are recognized through OCI in the period in which they occur. Actuarial gains and losses arise from experience adjustments and changes in actuarial assumptions. Remeasurements are not reclassified to profit or loss, from OCI, in subsequent periods.

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

In determining whether statutory minimum funding requirements of the 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. Decommissioning and restoration obligations for coal mines are incurred over time as new areas are mined, and a portion of the provision is settled over time as areas are reclaimed prior to final pit reclamation. Reclamation costs for mining assets are recognized on a unit-of-production basis.

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

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.

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.

Lessor

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 earnings 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 30 to 60 years. In developing these assumptions, management uses estimates of contracted and future market prices based on expected market supply and demand in the region in which the plant operates, anticipated production levels, planned and unplanned outages, changes to regulations and transmission capacity or constraints for the remaining life of the facilities.

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

The impairment outcome can also be impacted by the determination of CGUs or groups of CGUs for asset and goodwill impairment testing. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets, and goodwill is allocated to each CGU or group of CGUs that is expected to benefit from the synergies of the acquisition from which the goodwill arose. The allocation of goodwill is reassessed upon changes in the composition of segments, CGUs or groups of CGUs. In respect of determining CGUs, significant judgment is required to determine what constitutes independent cash flows between power plants that are connected to the same system. The 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 regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2019 to 2021 is found in Notes 7, 18 and 21.

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. See Note 12 for further details on the impacts of the Company's tax policies.

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 15. 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 fulfiled.

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, in determining the amount to be capitalized. Information on the write-off of project development costs is disclosed in Note 7.

VI. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(K) and Note 23. 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 2021 in respect of decommissioning and restoration provisions can be found in Notes 7 and 23.

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 18.

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. See Note 31 for disclosures on employee future benefits.

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 9 and 23 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.

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, which 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 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.

XIII. Change in Estimates

During the year ended Dec. 31, 2021, there were changes in estimates relating to defined benefit obligations and decommissioning and other provisions. Refer to Note 23 and 26 for further details. During the year ended Dec. 31, 2020, there were changes in estimates relating to the useful life of PP&E. Refer to Note 18 for further details.

3. Accounting Changes

A. Current Accounting Changes

I. Amendments to IAS 1 Presentation of Financial Statements: Material Accounting Policies

Effective for the 2021 annual financial statements, the Company early adopted amendments to IAS 1 *Presentation of Financial Statements* in advance of its mandatory effective date of Jan. 1, 2023, which requires entities to disclose their material accounting policy information rather than their significant accounting policies. The Company has updated the accounting policies disclosed in Note 2 based on its assessment of the amended standard.

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

Effective Jan. 1, 2021, the Company early adopted amendments to IAS 16 *Property, plant and equipment* ("IAS 16 Amendments") in advance of its mandatory effective date of Jan. 1, 2022. The Company adopted the IAS 16 Amendments retroactively. No cumulative effect of initially applying the guidance arose. The IAS 16 Amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in a manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. No adjustments resulted from early adopting the amendments.

III. IFRS 7 Financial Instruments: Disclosures — Interest Rate Benchmark Reform

The transition of the London Interbank Offered Rates ("LIBOR") has begun with the cessation of the publication of one-week and two-month USD LIBOR occurring on Dec. 31, 2021. The remaining overnight, one-, three-, six-, and 12-month USD LIBOR will continue to be published until their cessation date on June 30, 2023. Existing financial instruments may continue to use USD LIBOR while they are published until they mature, however, new financial instruments will not be using USD LIBOR if entered into after Dec. 31, 2021. The IASB issued Interest Rate Benchmark Reform — Phase 2 in August 2020, which amends IFRS 9 *Financial Instruments*, IAS 39 *Financial instruments: Recognition and Measurement*, IFRS 7 *Financial Instruments: Disclosures* and IFRS 16 *Leases*. The amendments were effective Jan. 1, 2021, and were adopted by the Company on Jan. 1, 2021. There was no financial impact upon adoption.

The Company's credit facilities references USD LIBOR for US-dollar drawings and the Canadian Dollar Offered Rate for Canadian drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. For the year ended Dec. 31, 2021, there were no drawings under the credit facilities. The Company has interest rate swap agreements in place with a notional amount of US$150 million referencing three-month LIBOR, expected to settle in the third quarter of 2022.

B. Future Accounting Changes

I. Amendments to 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 will be adopted by the Company in 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 financial impact is expected upon adoption.

II. 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.

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

In January 2020, 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, provide 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, 2023, and are to be applied retrospectively. The Company has not yet determined the impact of these amendments 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 and Divestitures

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 (A) Nov. 5, 2021	Ada facility (B) May 19, 2020
Assets		
Cash and cash equivalents	4	1
Accounts receivable	4	3
Property, plant and equipment	146	1
Intangible assets(1)	—	37
Right of use assets	13	—
Inventory	—	1
Prepaid expenses	—	1
Liabilities		
Accounts payable and accrued liabilities	(4)	—
Lease liabilities	(13)	—
Tax equity liability	(20)	—
Deferred taxes	(3)	—
Risk management liabilities (current and long-term)	—	(5)
Decommissioning provisions	(4)	(1)
Net assets acquired	**123**	38
Cash consideration	**120**	32
Working capital consideration	**3**	6
Total purchase consideration transferred	**123**	38

1) This relates to the power sales contract acquired and is being amortized over six years.

A. 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. The acquisition was funded using existing liquidity. The North Carolina Solar facility consists of 20 solar photovoltaic sites across North Carolina. The sites were commissioned between November 2019 and May 2021 and are all operational. The facility is secured by long-term PPAs with Duke Energy, which have an average remaining term of 12 years. Under the PPAs, Duke Energy receives the renewable electricity, capacity and environmental attributes from each facility.

Certain assets and liabilities have been measured on a provisional basis. If new facts and circumstances are obtained within one year from the date of acquisition that existed at the date of acquisition, any identified adjustments to the above amounts or additional provisions that existed at the date of acquisition, may result in a revision to the accounting for the acquisition.

Had North Carolina Solar been acquired at the beginning of the year, the assets would have contributed an estimated $16 million to revenues and $9 million to net earnings before taxes.

At the closing of the acquisition, TransAlta Renewables Inc. ("TransAlta Renewables"), a subsidiary of the Company, acquired a 100 per cent economic interest in North Carolina Solar from a wholly owned subsidiary of the Company through a tracking preferred share structure for aggregate consideration of approximately US$102 million.

B. Acquisition of the Ada Facility

On May 19, 2020, the Company closed the acquisition of a contracted natural-gas-fired cogeneration facility from two private companies for a purchase price of US$27 million. The Ada facility is a 29 MW cogeneration facility in Michigan that is contracted under a PPA and a steam sale agreement for approximately 6 years with Consumers Energy and Amway.

C. Sale of Pioneer Pipeline

On June 30, 2021, the Company closed the sale of the Pioneer Pipeline to ATCO Gas and Pipelines Ltd. ("ATCO") for the aggregate sale price of $255 million. The net cash proceeds to TransAlta from the sale of its 50 per cent interest was approximately $128 million, subject to certain adjustments.

As a result of this sale, the Company has derecognized the related Pioneer Pipeline assets that were classified as assets held for sale of $97 million and recognized a gain on sale of $31 million on the statement of earnings. In addition, 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 a lease liability of $43 million related to the pipeline, resulting in a gain of $2 million.

5. Revenue

A. Disaggregation of Revenue

The majority of the Company's revenues are derived from the sale of physical power, capacity and environmental attributes, leasing of power facilities, and from asset optimization activities, which the Company disaggregates into the following groups for the purpose of determining how economic factors affect the recognition of revenue.

Year ended Dec. 31, 2021	Hydro	Wind and Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other[(3)]	28	207	395	24	–	–	654
Environmental attributes	–	28	–	–	–	–	28
Revenue from contracts with customers	28	235	395	24	–	–	682
Revenue from leases[(4)]	–	–	19	–	–	–	19
Revenue from derivatives and other trading activities	–	(25)	(118)	138	211	4	210
Merchant revenue and other[(3)(5)]	355	95	813	547	–	–	1,810
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) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) The Alberta PPAs for certain facilities included in the Hydro, Gas and Energy Transition segments with the Balancing Pool expired at Dec. 31, 2020. These facilities began operating on a merchant basis in the Alberta market on Jan. 1, 2021.
(4) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(5) Includes merchant revenue, government incentives and other miscellaneous.

Year ended Dec. 31, 2020	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	141	238	465	156	—	—	1,000
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	141	261	465	156	—	—	1,023
Revenue from leases[3]	—	—	123	—	—	—	123
Revenue from derivatives and other trading activities	—	(2)	(8)	283	122	12	407
Merchant revenue and other[4]	11	70	207	265	—	(5)	548
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) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue, government incentives and other miscellaneous.

Year ended Dec. 31, 2019	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers							
Power and other	142	221	497	185	—	—	1,045
Environmental attributes	—	23	—	—	—	—	23
Revenue from contracts with customers	142	244	497	185	—	—	1,068
Revenue from leases[3]	—	—	130	—	—	—	130
Revenue from derivatives and other trading activities	—	18	(15)	160	129	4	296
Merchant revenue and other[4]	14	50	239	560	—	(10)	853
Total revenue	156	312	851	905	129	(6)	2,347
Revenues from contracts with customers							
Timing of revenue recognition							
At a point in time	—	27	5	46	—	—	78
Over time	142	217	492	139	—	—	990
Total revenue from contracts with customers	142	244	497	185	—	—	1,068

(1) This segment includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal. Refer to Note 1 for further details.
(2) This segment includes the segment previously known as Centralia and the facilities not converted to gas previously in the Alberta Thermal. Refer to Note 1 for further details.
(3) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases.
(4) Includes merchant revenue, government incentives and other miscellaneous.

B. Contract Liabilities

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

Contract liabilities	2021	2020
Balance, beginning of the year	**15**	15
Amounts transferred to revenue included in opening balance	**(1)**	(1)
Consideration received	**8**	1
Increases due to amounts billed to customers	**—**	2
Changes in transaction price	**11**	—
Performance obligations satisfied	**(1)**	(2)
Balance, end of year	**32**	15
Current portion	**19**	1
Long-term portion	**13**	14

The contract liabilities outstanding at Dec. 31, 2021, and Dec. 31, 2020, primarily relate to prepayments relating to the Company's New Richmond and Bone Creek facilities where the Company still has to fulfil its performance obligations. In addition, the Company recognized a provision for liquidated damages due to the Sarnia outages that occurred in the second quarter of 2021.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the invoice practical expedient and contracts with an original expected duration of less than 12 months.

Additionally, 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. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved.

Contracts with customers that are accounted for as derivatives are excluded from these disclosures. Refer to Note 15 for further details. Contracts that have been executed for development projects are excluded until commercial operations have been achieved.

As a result, the amounts of future revenues disclosed below represent only a portion of future revenues that are expected to be realized by the Company from its contractual portfolio.

Hydro

At Dec. 31, 2020, the Company's PPA with the Balancing Pool to provide the capacity of 12 hydro facilities throughout the province of Alberta concluded. Commencing Jan. 1, 2021, production has been sold into the Alberta merchant market.

The Company has contracts for services at specific hydro facilities, which will conclude at the end of 2030. The Company also has a contract with the Government of Alberta to manage water for flood and drought mitigation purposes, which concludes in 2026. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $46 million.

Wind and Solar

At Dec. 31, 2021, the Company had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind facilities located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Company expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures.

The Company also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchasers over the remaining terms of the contracts, from 2022 through 2024. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $9 million.

Gas

At Dec. 31, 2020, the Company's PPAs with the Balancing Pool for capacity and electricity from the Keephills Unit 2 and Sheerness Units 1 and 2 legacy coal facilities concluded. Future production has been sold into the merchant market.

At Dec. 31, 2021, the Company has contracts with customers to deliver energy services from one of its gas facilities in Ontario. The contracts all consist of a single performance obligation requiring the Company to stand ready to deliver electricity and steam. On May 12, 2021, the Company executed an Amended and Restated Energy Supply Agreement with one of its large industrial customers at the Sarnia cogeneration facility that provides for the supply of electricity and steam. This agreement will extend the term of the original agreement from Dec. 31, 2022 to Dec. 31, 2032. However, if TransAlta is unable to enter into a new contract with the Ontario Independent Electricity System Operator or enter into agreements with its other industrial customers at the Sarnia cogeneration facility that extend past Dec. 31, 2025, then the Company has the option to provide notice of termination in 2022 that would terminate the Amended and Restated Energy Supply Agreement four years following such notice. The Company currently expects to recognize revenue as it delivers electricity and steam to the other industrial customers at the Sarnia cogeneration facility until the completion of the contracts in late 2025, or 2032, if the contract is extended.

At the same gas facility, the Company has a contract with the local power authority with fixed capacity charges that are adjusted for seasonal fluctuations, steam demand from the plant's other customers and for deemed net revenue related to production of electricity into the market. As a result, revenues recognized in the future will vary as they are dependent upon factors outside of the Company's control and are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Company expects to recognize such revenue as it stands ready to deliver electricity until the completion of the contract term on Dec. 31, 2025.

At Dec. 31, 2021, the Company had contracts with customers to deliver steam, hot water and chilled water from one of its other gas facilities in Ontario, extending through 2023 and 2033. Prices under these contracts include fixed annual fees, variable thermal energy charges based on gas prices, and fixed base amounts per gigajoule, subject to escalation annually for both gas prices and inflation. One contract includes minimum annual take-or-pay volumes. Estimated future revenues related to the remaining performance obligations for this contract as of Dec. 31, 2021, are approximately $31 million.

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

The Company has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer in Canada, under which the Company will receive a fixed capacity payment and variable energy payments based on production. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2021, are approximately $336 million, of which the Company expects to recognize on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

At Dec. 31, 2021, the Company has PPAs with customers to deliver electricity from its gas facilities located in Australia. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. The variable revenues under the contracts are considered to be fully constrained and are excluded from these disclosures. Another one of the Company's PPA to deliver electricity from its gas facilities is considered a finance lease resulting in some revenues being classified for accounting purposes as finance lease income and are excluded from these disclosures. The Company also earns revenues from providing operation and maintenance services for the facility for a fixed monthly fee. Estimated future revenues related to the remaining performance obligations for these contracts as at Dec. 31, 2021, are approximately $2.5 billion, of which the Company expects to recognize approximately $285 million in total over the next two fiscal years and on average, between approximately $85 million to $145 million annually thereafter for the duration of the remaining contract.

Energy Transition

At Dec. 31, 2020, the Company's PPAs with the Balancing Pool for capacity and electricity from the Keephills Unit 1 coal facility concluded. Commencing Jan. 1, 2021, production has been sold into the merchant market.

6. Expenses by Nature

Fuel and purchased power and operations, maintenance and administrative ("OM&A") expenses classified by nature are as follows:

Year ended Dec. 31	**2021**		2020		2019	
	Fuel and purchased power	**OM&A**	Fuel and purchased power	OM&A	Fuel and purchased power	OM&A
Gas fuel costs[1]	**306**	**—**	159	—	133	—
Coal fuel costs[1][2]	**164**	**—**	269	—	310	—
Royalty, land lease, other direct costs	**19**	**—**	20	—	21	—
Purchased power	**339**	**—**	163	—	246	—
Mine depreciation[3]	**190**	**—**	144	—	119	—
Salaries and benefits	**36**	**234**	50	235	52	228
Other operating expenses[4]	**—**	**277**	—	237	—	247
Total	**1,054**	**511**	805	472	881	475

(1) During 2021, fuel costs have been split to show natural gas and coal fuel costs separately within the above table and carbon compliance costs have been reclassified from fuel and purchased power to a separate line called carbon compliance costs on the Consolidated Statements of Earnings (Loss). Prior periods have been adjusted to reflect these reclassifications.
(2) Included in coal fuel costs for 2021 was $17 million related to the impairment of coal inventory recorded during 2021 (2020 — $15 million). Refer to Note 17 for further details.
(3) Included in mine depreciation for 2021 was $48 million related to the mine depreciation that was initially recorded in the standard cost of coal inventory and then subsequently impaired during 2021 (2020 — $22 million) . Refer to Note 17 for further details.
(4) 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. Refer to Note 17 for further details.

7. Asset Impairment

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 for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Company's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2072.

	2021	2020	2019
PP&E Impairments:			
Energy Transition facilities and projects (reversals)	**345**	79	(151)
Energy Transition - Centralia mine decommissioning and restoration provision	**—**	3	141
Changes in decommissioning and restoration provisions for retired assets(1)	**32**	—	2
Highvale mine	**195**	—	—
Kaybob Cogeneration Project	**27**	—	—
Wind	**12**	—	—
Hydro	**5**	2	—
Gas	**5**	—	—
Intangible asset impairment - coal rights(2)	**17**	—	—
Assets held for sale(3)	**—**	—	15
Project development costs(4)	**10**	—	18
Asset impairment	**648**	84	25

(1) Changes related to changes in discount rates on retired assets.
(2) Impaired to nil as no future coal will be extracted from this area of the mine.
(3) 2019 amounts relate to trucks and associated inventory to be sold within the Energy Transition segment and accordingly, these items were impaired to net realizable value.
(4) During 2021, the Company recorded an impairment 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. During 2020, the Company wrote off nil (2019 — $18 million) in project development costs related to projects that are no longer proceeding within the Corporate segment.

A. Energy Transition Asset Impairments

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), 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 equipment for 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, of which $25 million was related to assets held for sale. 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 2020, the Company recognized an impairment 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.

In 2019, an internal valuation indicated the fair value less costs of disposal of the Centralia thermal facility CGU exceeded the carrying value, resulting in a recoverability test in 2019. The updated fair value included sustained changes in the market power price and cost of coal due to contract renegotiation. As a result of the recoverability test, an impairment reversal of $151 million was recorded in the Centralia segment.

B. Highvale Mine

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.

C. Kaybob Cogeneration Project

On Oct. 1, 2019, TransAlta and Energy Transfer Canada ("ET Canada" formerly known as SemCAMS Midstream ULC) entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. The facility was expected to receive its final regulatory approvals in the second half of 2020 and begin construction in December 2020. On Sept. 25, 2020, the Alberta Utilities Commission ("AUC") released a decision in which it approved the construction and operation of the facility, but denied the application for the Industrial System Designation. TransAlta will not be proceeding with the Kaybob cogeneration facility as a result of ET Canada's purported termination of the agreements to develop, construct and operate the 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing plant. As a result, the Company recorded an impairment 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. TransAlta has commenced an arbitration seeking compensation for ET Canada's wrongful termination of the agreements. Refer to Note 36 for further details.

D. Wind Facilities

During the third quarter of 2021, the Company recorded an impairment of $10 million for a wind asset as result of an increase in estimated decommissioning costs after the review of a recent engineering study on the decommissioning costs of the wind sites. Refer to Note 23 for more details for changes in decommissioning and restoration provisions. The resulting fair value measurement less cost of disposal is categorized as a Level III fair value measurement and the Company has adjusted the expected value down to $65 million using discount rates of 5.0 per cent (Dec. 31, 2020 — 5.3 per cent). The key assumptions impacting the determination of fair value are electricity production, sales prices and cost inputs, which are subject to measurement uncertainty.

During 2021, the Company recognized an impairment 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. Refer to Note 24 for further details.

E. Impairment on Decommissioning and Restoration Provision on Retired Assets

During 2019, the Company adjusted the Centralia mine decommissioning and restoration provision as management no longer believed that the fine coal recovery and reclamation work will occur as originally proposed. At the end of 2019, the Company's best estimate of the decommissioning and restoration provision increased by $141 million. Since the Centralia mine is no longer operating and reached the end of its useful life in 2006, this adjustment resulted in the immediate recognition of the full $141 million, through asset impairment charges to net earnings.

8. 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	**2021**		2020	
	Minimum lease receipts	**Present value of minimum lease receipts**	Minimum lease receipts	Present value of minimum lease receipts
Within one year	**58**	**54**	63	56
Second to fifth years inclusive	**127**	**105**	169	126
More than five years	**80**	**66**	100	82
	265	**225**	332	264
Less: unearned finance lease income	**40**	**—**	68	—
Total finance lease receivables	**225**	**225**	264	264

	2021	2020
Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease receivables (Note 14)	**40**	36
Long-term portion of finance lease receivables	**185**	228
Total finance lease receivables	**225**	264

On Oct. 22, 2020, Southern Cross Energy ("SCE"), a subsidiary of the Company, replaced and extended its current long-term PPA with BHP Billiton Nickel West Pty Ltd. ("BHP"). The new agreement was effective Dec. 1, 2020, and replaces the previous contract that was scheduled to expire Dec. 31, 2023. The amendment to the PPA extends the term to Dec. 31, 2038, and provides SCE with the exclusive right to supply thermal and electrical energy from the Southern Cross Facilities for BHP's mining operations located in the Goldfields region of Western Australia. For accounting purposes, the original agreement was accounted for as an operating lease. Under the new PPA, the agreement is now accounted for as a finance lease.

As a result, in 2020, the Company derecognized net assets of $77 million, which included balances for PP&E, intangible assets, deferred credits and prepaid expenses. In addition, the Company recognized a finance lease receivable of $89 million and a gain on asset disposition of $12 million. Subsequent to the transaction, the Company incurred additional major maintenance costs in relation to these assets which was recorded as a reduction to the gain on asset disposition.

9. Net Other Operating Expense (Income)

Net other operating income includes the following:

Year ended Dec. 31	**2021**	2020	2019
Alberta Off-Coal Agreement	**(40)**	(40)	(40)
Supplier settlements	**34**	—	—
Onerous contract provisions	**14**	29	—
Insurance recoveries and other[1]	**—**	—	(9)
Net other operating expense (income)	**8**	(11)	(49)

(1) There were no insurance recoveries in 2021 or 2020. In 2019, the Company received $10 million in insurance recoveries related to insurance proceeds for tower fires at Wyoming and Summerview.

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. In July 2018, the Company obtained financing against the OCA payments. Refer to Note 24 for further details.

B. Supplier Settlements

During 2021, $34 million was expensed relating 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.

C. 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 accelerate plans 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.

10. 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.

The change in investments is as follows:

	Skookumchuck	EMG	Total
Balance, Dec. 31, 2019	—	—	—
Contributions	86	16	102
Equity income	1	—	1
Change in foreign exchange rates	(2)	(1)	(3)
Balance, Dec. 31, 2020	85	15	100
Equity income	12	(3)	**9**
Distributions received	(4)	—	**(4)**
Balance, Dec. 31, 2021	**93**	**12**	**105**

A. Skookumchuck Wind Project

On Nov. 25, 2020, TransAlta completed the purchase of a 49 per cent interest in SP Skookumchuck Investments, LLC from Southern Power for cash consideration of $86 million (US$66 million). Skookumchuck is a 136.8 MW wind project located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas V136 wind turbines. The project has a 20-year PPA with Puget Sound Energy.

B. EMG International Acquisition

On Nov. 30, 2020, TransAlta acquired a 30 per cent equity interest in EMG. Included in the purchase price of US$12 million is an estimated component contingent on EMG realizing certain earnings metrics in 2020 and 2021, following the acquisition. The final contingent amount will be calculated based on actual earnings metrics achieved. EMG is an established company with over 25 years of experience in process wastewater treatment and specializes in the design and construction of high-rate anaerobic digester systems. The investment provides an opportunity for TransAlta to leverage its expertise in on-site generation to support further advancements by EMG in the waste-to-energy space and will advance the Company's Clean Electricity Growth plan in the US market .

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	2021	2020
Results of operations		
Revenues	**19**	3
Expenses	**(10)**	(2)
Proportionate share of net earnings	**9**	1

11. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	**2021**	2020	2019
Interest on debt	**163**	158	161
Interest on exchangeable debentures (Note 25)	**29**	29	20
Interest on exchangeable preferred shares (Note 25)	**28**	5	—
Interest income	**(11)**	(10)	(13)
Capitalized interest (Note 18)	**(14)**	(8)	(6)
Interest on lease liabilities	**7**	8	4
Credit facility fees, bank charges and other interest	**18**	18	15
Tax shield on tax equity financing (Note 24)(1)	**(9)**	1	(35)
Interest on line loss rule proceeding (Note 36(H)(I))	**—**	5	—
Other(2)	**2**	2	10
Accretion of provisions (Note 23)	**32**	30	23
Net interest expense	**245**	238	179

(1) Credit in 2021 primarily relates to the tax benefit associated with investment tax credits claimed in 2021 on the North Carolina Solar projects that was assigned to the tax equity investor. Credit in 2019 primarily relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim projects that was assigned to the tax equity investor. The tax equity 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.
(2) In 2021, other interest expense included approximately nil (2020 — nil , 2019 — $5 million) for the significant financing component required under IFRS 15.

12. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	**2021**	2020	2019
Earnings (loss) before income taxes	**(380)**	(303)	193
Net earnings (loss) attributable to non-controlling interests not subject to tax	**(33)**	2	(26)
Adjusted earnings (loss) before income taxes	**(413)**	(301)	167
Statutory Canadian federal and provincial income tax rate (%)	**23.6%**	24.5%	26.5%
Expected income tax expense (recovery)	**(98)**	(74)	44
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**4**	3	5
Deferred income tax expense related to temporary difference on investment in subsidiaries	**—**	9	—
Write-down (reversal of write-down) of unrecognized deferred income tax assets	**134**	8	(9)
Statutory and other rate differences	**4**	(7)	(31)
Other	**1**	11	8
Income tax expense (recovery)	**45**	(50)	17
Effective tax rate (%)	**(11%)**	17%	10%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	**2021**	2020	2019
Current income tax expense	**56**	35	35
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(145)**	(95)	22
Deferred income tax expense related to temporary difference on investment in subsidiary	**—**	9	—
Deferred income tax recovery resulting from changes in tax rates or laws	**—**	(7)	(31)
Deferred income tax expense (recovery) arising from the unrecognized deferred income tax assets(1)	**134**	8	(9)
Income tax expense (recovery)	**45**	(50)	17

Year ended Dec. 31	**2021**	2020	2019
Current income tax expense	**56**	35	35
Deferred income tax recovery	**(11)**	(85)	(18)
Income tax expense (recovery)	**45**	(50)	17

(1) During the year ended Dec. 31, 2021, the Company recorded a write-down of deferred tax assets of $134 million (2020 —$8 million write-down, 2019 — $9 million write-down reversal). In the current year additional deferred tax assets were created from the recognition of other comprehensive losses in the US. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Company's directly owned US operations and Canadian operations. The Company evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Company's directly owned US operations to utilize the underlying tax losses.

B. Consolidated Statements of Changes in Equity

The aggregate current and deferred income tax related to items charged or credited to equity are as follows:

Year ended Dec. 31	**2021**	2020	2019
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(57)**	(23)	6
Net actuarial gains (losses)	**11**	(3)	(7)
Income tax recovery reported in equity	**(46)**	(26)	(1)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	**2021**	2020
Net operating loss carryforwards(1)	**530**	469
Future decommissioning and restoration costs	**183**	140
Property, plant and equipment	**(651)**	(717)
Risk management assets and liabilities, net	**(53)**	(107)
Employee future benefits and compensation plans	**53**	62
Interest deductible in future periods	**17**	22
Foreign exchange differences on US-denominated debt	**16**	31
Other deductible temporary differences	**(5)**	2
Net deferred income tax liability, before write-down of deferred income tax assets	**90**	(98)
Unrecognized deferred income tax assets	**(380)**	(247)
Net deferred income tax liability, after write-down of deferred income tax assets	**(290)**	(345)

(1) Net operating losses expire between 2031 and 2040.

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

As at Dec. 31	**2021**	2020
Deferred income tax assets(1)	**64**	51
Deferred income tax liabilities	**(354)**	(396)
Net deferred income tax liability	**(290)**	(345)

(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, 2021, the Company had recognized a net liability of nil (2020 – nil) related to uncertain tax positions.

Ongoing CRA Audit

The Company is subject to routine audits of its tax filing positions by the Canada Revenue Agency ("CRA") on an ongoing basis. The CRA is currently examining the Company's tax filings for the 2015 taxation year and, in connection with such audit, is reviewing the internal reorganization completed in 2015. To date, the CRA has not proposed any reassessment of the Company's tax liability as a consequence of such audit and management believes that any reassessment would be without merit. The Company strongly believes that the Company's tax filing positions are appropriate, and accordingly no amounts have been accrued in the consolidated financial statements in respect of any such potential reassessment. If a notice of reassessment were issued, the Company would expect to vigorously oppose any such reassessment. If the CRA were to issue such a reassessment, the Company would be required to pay, on a provisional basis, up to 50 per cent of the amounts assessed, estimated to be between nil and $57 million. Any payment made by the Company in this context would be held by CRA until the final resolution of the dispute. The Company firmly believes it will be able to successfully defend its original filing position so that, ultimately, no increased income tax payable will result from the CRA's audit and any amounts paid to the CRA by the Company would be refunded.

13. 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, 2021**
TransAlta Cogeneration L.P.	49.99% — Canadian Power Holdings Inc.
TransAlta Renewables	39.9% — Public shareholders
Kent Hills Wind LP[1]	17% — Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

TransAlta Cogeneration, L.P. ("TA Cogen") operates a portfolio of cogeneration facilities in Canada and owns 50 per cent of a dual-fuel generating facility. TransAlta Renewables owns and operates a portfolio of gas and renewable power generation facilities in Canada and owns economic interests in various other gas and renewable facilities of the Company.

Summarized financial information relating to subsidiaries with significant non-controlling interests is as follows:

A. TransAlta Renewables

The net earnings, distributions and equity attributable to non-controlling interests include the 17 per cent non-controlling interest in the 167 MW Kent Hills wind facility located in New Brunswick.

Year ended Dec. 31	**2021**	2020	2019
Revenues	**470**	436	446
Net earnings	**139**	97	183
Total comprehensive earnings	**66**	223	138
Amounts attributable to the non-controlling interests:			
Net earnings	**50**	40	73
Total comprehensive earnings	**21**	90	56
Distributions paid to non-controlling interests	**100**	80	69

As at Dec. 31	**2021**	2020
Current assets	**430**	743
Long-term assets	**3,319**	2,913
Current liabilities	**(593)**	(364)
Long-term liabilities	**(1,033)**	(987)
Total equity	**(2,123)**	(2,305)
Equity attributable to non-controlling interests	**(869)**	(948)
Non-controlling interests' share (per cent)	**39.9**	39.9

In 2020, the Company's ownership per cent decreased from 60.4 per cent in 2019 to 60.1 per cent due to TransAlta Renewables issuing approximately 1 million common shares under their Dividend Reinvestment Plan ("DRIP"). The Company did not participate in this plan. In the fourth quarter of 2020, TransAlta Renewables suspended the DRIP in respect of any future declared dividends.

B. TA Cogen

Year ended Dec. 31	2021	2020	2019
Results of operations			
Revenues	**265**	146	181
Net earnings (loss)	**103**	(13)	43
Total comprehensive earnings (loss)	**103**	(13)	43
Amounts attributable to the non-controlling interest:			
Net earnings (loss)	**62**	(6)	21
Total comprehensive earnings (loss)	**62**	(6)	21
Distributions paid to Canadian Power Holdings Inc.	**56**	17	37

As at Dec. 31	2021	2020
Current assets	**66**	69
Long-term assets	**312**	323
Current liabilities	**(52)**	(78)
Long-term liabilities	**(36)**	(37)
Total equity	**(290)**	(277)
Equity attributable to Canadian Power Holdings Inc.	**(142)**	(136)
Non-controlling interest share (per cent)	**49.99**	49.99

In 2020, the Balancing Pool PPA concluded and the Sheerness facility became a merchant facility in 2021. This resulted in new protocols under the amended contractual agreement whereby the revenue and cost of sales for the facility are allocated based on dispatch activities. Capital and operating expenses continue to be allocated based on ownership interest.

14. Trade and Other Receivables

As at Dec. 31	2021	2020
Trade accounts receivable	**499**	488
Collateral paid (Note 16)	**55**	49
Current portion of finance lease receivables (Note 8)	**40**	36
Loan receivable (Note 22)	**55**	—
Income taxes receivable	**2**	10
Trade and other receivables	**651**	583

15. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost. The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 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 receivable	–	–	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 (Note 25)	–	–	735	735

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

Carrying value as at Dec. 31, 2020

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents(1)	–	–	703	703
Restricted cash	–	–	71	71
Trade and other receivables	–	–	583	583
Long-term portion of finance lease receivables	–	–	228	228
Risk management assets				
Current	102	69	–	171
Long-term	471	50	–	521
Other assets (Note 22)	–	–	52	52
Financial liabilities				
Accounts payable and accrued liabilities	–	–	599	599
Dividends payable	–	–	59	59
Risk management liabilities				
Current	10	84	–	94
Long-term	–	68	–	68
Credit facilities, long-term debt and lease liabilities(2)	–	–	3,361	3,361
Exchangeable securities (Note 25)	–	–	730	730

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

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the 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.

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 historical bootstrap models may be employed. The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatility and correlations between products derived from historical price relationships.

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 businesses in relation to trading activities and certain contracting activities. To the extent applicable, changes in net risk management assets and liabilities for non-hedge positions are reflected within earnings of these businesses.

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2021, are as follows: Level I – $12 million net asset (Dec. 31, 2020 – $13 million net liability), Level II – $122 million net asset (Dec. 31, 2020 – $27 million net liability) and Level III – $159 million net asset (Dec. 31, 2020 – $582 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2021, are primarily attributable to volatility in market prices on both existing contracts and new contracts as well as contract settlements.

The following tables summarize 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, 2021 and 2020, respectively:

	Year ended Dec. 31, 2021			Year ended Dec. 31, 2020		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**573**	**9**	**582**	678	8	686
Changes attributable to:						
Market price changes on existing contracts	**(181)**	**4**	**(177)**	(18)	3	(15)
Market price changes on new contracts	**—**	**(134)**	**(134)**	—	7	7
Contracts settled	**(107)**	**(5)**	**(112)**	(71)	(10)	(81)
Change in foreign exchange rates	**—**	**—**	**—**	(16)	1	(15)
Net risk management assets (liabilities) at end of period	**285**	**(126)**	**159**	573	9	582
Additional Level III information:						
Losses recognized in other comprehensive earnings	**(181)**	**—**	**(181)**	(34)	—	(34)
Total gains (losses) included in earnings before income taxes	**107**	**(130)**	**(23)**	71	11	82
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(135)**	**(135)**	—	1	1

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, 2021, the total Level III risk management asset balance was $305 million (2020 – $615 million) and Level III risk management liability balance was $146 million (2020 – $33 million). 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. 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. During 2021, the sensitivities include the effects of liquidity and credit value adjustments.

As at		**Dec. 31, 2021**		
Description	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Reasonable 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 price increase of US$20
Coal transportation – US	+3 -18	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or price increase of US$20 80% to 120% zero to 4%
Full requirements – Eastern US	+9 -9	Historical bootstrap	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+17 -16	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price decrease of 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) Wind discounts	Price decrease of C$24 or increase of C$5 5% decrease or 5% increase
Long-term wind energy sale - Central US	+27 -15	Long-term price forecast	Illiquid future power prices (per MWh) Wind discounts	Price decrease of US$2 or increase of US$3 3% decrease or 3% increase
Others	+6 -6			

As at		Dec. 31, 2020		
Description	Sensitivity	Valuation technique	Unobservable input	Reasonable possible change
Long-term power sale – US	+35 -59	Long-term price forecast	Illiquid future power prices (per MWh)	Price decrease of US$3 or a price increase of US$5
Coal transportation – US	+3 -5	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	Price decrease of US$3 or a price increase of US$5 80% to 120% zero to 4%
Full requirements – Eastern US	+3 -3	Historical bootstrap	Volume Cost of supply	95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	+22 -22	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	Price increase or decrease of US$6 Price increase or decrease of US$1
Others	+5 -5			

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 2023, 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 remained consistent from Dec. 31, 2020, to Dec. 31, 2021, resulting in the sensitivity values remaining consistent. The balance for this contract at Dec. 31, 2021 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, with a contract start date of Jan. 1, 2021, that extends until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

The key unobservable inputs used in the valuation include non-liquid power prices, option volatility and rail rate escalation. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

For periods beyond 2023, 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. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement.

iv. Long-Term Wind Energy Sale – Eastern US

In relation to the Big Level wind facility, the Company has a long-term contract for differences whereby the Company receives a fixed price per MWh and pays the prevailing real-time energy market price per MWh as well as the physical delivery of renewable energy credits based on proxy generation. Commercial operation of the facility was achieved in December 2019, with the contract commencing on July 1, 2019, and extending for 15 years after the commercial operation date. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and non-liquid forward prices for power and RECs.

v. Long-Term Wind Energy Sale – Canada

In relation to the Garden Plain wind project, the Company has entered into a virtual PPA whereby the Company receives the difference between the fixed contract price per MWh and the Alberta Electric System Operator ("AESO") settled pool price per MWh. The contract commences on commercial operation of the facility, which is expected by the end of 2022, and extending for 18 years past that date. The energy component of the contract is accounted for at fair value through profit or loss.

In addition to the virtual PPA contract, the Company has entered into a "bridge contract" that runs 16 months from Sept. 1, 2021 through Dec. 31, 2022, with the potential for extension at the virtual PPA price, depending on the commencement of commercial operations.

Under a separate agreement, Pembina has the option to purchase a 37.7 per cent interest in the project (49 per cent of the PPA). The option must be exercised no later than 30 days after commercial operational date.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and monthly wind discounts.

vi. *Long-Term Wind Energy Sale – Central US*

On Dec. 22, 2021, TransAlta executed two long-term virtual PPAs for the off take of 100 per cent of the generation from its 300 MW White Rock East and White Rock West wind power projects (collectively, the "White Rock Wind Projects") to be located in Caddo County, Oklahoma. The Company receives the difference between the fixed contract price per MWh and the settled pool price per MWh. The contracts commence on commercial operation of the facilities, which is expected within the second half of 2023, and extend for 15 years past that date. The energy component of the contracts is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contracts are the non-liquid forward prices for power and monthly 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 asset fair value of $8 million as at Dec. 31, 2021 (Dec. 31, 2020 – $12 million net liability) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the year ended Dec. 31, 2021, are primarily attributable to favourable market prices on existing contracts.

IV. Other Financial Assets and Liabilities

The fair value of financial assets and liabilities measured at other than fair value is as follows:

	Fair value[1]				Total carrying value[1]
	Level I	Level II	Level III	Total	
Exchangeable securities — Dec. 31, 2021	**—**	**770**	**—**	**770**	**735**
Long-term debt — Dec. 31, 2021	**—**	**3,272**	**—**	**3,272**	**3,167**
Exchangeable securities — Dec. 31, 2020	—	769	—	769	730
Long-term debt — Dec. 31, 2020	—	3,480	—	3,480	3,227

(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 paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 22) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses

The majority of derivatives traded by the 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 15 above for fair value Level III valuation techniques used. In some instances, a difference may arise between the fair value of a financial instrument at initial recognition (the "transaction price") and the amount calculated through a valuation model. This unrealized gain or loss at inception is recognized in net earnings (loss) only if the fair value of the instrument is evidenced by a quoted market price in an active market, observable current market transactions that are substantially the same, or a valuation technique that uses observable market inputs. Where these criteria are not met, the difference is deferred on the Consolidated Statements of Financial Position in risk management assets or liabilities, and is recognized in net earnings (loss) over the term of the related contract. The difference between the transaction price and the fair value determined using a valuation model, yet to be recognized in net earnings, and a reconciliation of changes is as follows:

As at Dec. 31	2021	2020	2019
Unamortized net gain (loss) at beginning of year	**(33)**	9	49
New inception gain (loss)[1]	**(50)**	(13)	3
Amortization recorded in net earnings during the year	**(19)**	(29)	(43)
Unamortized net gain (loss) at end of year[2]	**(102)**	(33)	9

(1) During 2021, the Company entered into PPAs for the White Rock Wind Projects 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 power agreement contract period. 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.
(2) During 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day one forward price curve at inception of the contract.

16. 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, 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**

As at Dec. 31, 2020	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	101	(11)	90
Long-term	471	(19)	452
Net commodity risk management assets (liabilities)	572	(30)	542
Other			
Current	(9)	(4)	(13)
Long-term	—	1	1
Net other risk management liabilities	(9)	(3)	(12)
Total net risk management assets (liabilities)	563	(33)	530

I. 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	**2021**				2020			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**394**	**330**	**(306)**	**(122)**	120	69	(132)	(104)
Gross amounts set-off	**(137)**	**(53)**	**138**	**54**	(69)	(10)	69	10
Net amounts as included in the Consolidated Statements of Financial Position	**257**	**277**	**(168)**	**(68)**	51	59	(63)	(94)

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 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 pre-defined hedging plan, including fixed price financial power swaps and long-term physical power sale contracts to hedge commodity price for electricity generation; and
- A committee dedicated to overseeing the risk and compliance program in trading and ensuring the existence of appropriate controls, processes, systems and procedures to monitor adherence to the program.

The Company has executed commodity price hedges for its Centralia thermal facility and for its portfolio of merchant power exposure in Alberta, including a long-term physical power sale contract at Centralia and fixed price financial swaps for the Alberta portfolio to hedge the prices. Both hedging strategies fall under the Company's risk management strategy used to hedge commodity price risk.

There is no source of hedge ineffectiveness for the merchant power exposure in Alberta.

Market risk exposures are measured using Value at Risk ("VaR") supplemented by sensitivity analysis. There has been no change to the Company's exposure to market risks or the manner in which these risks are managed or measured.

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, 2021, associated with the Company's proprietary trading activities was $2 million (2020 — $1 million, 2019 — $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, 2021, associated with the Company's commodity derivative instruments used in generation hedging activities was $33 million (2020 — $12 million, 2019 — $25 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, 2021, associated with these transactions was $51 million (2020— $15 million, 2019 — $8 million).

iii. Commodity Price Risk Management – Hedges

The Company's outstanding commodity derivative instruments designated as hedging instruments are as follows:

As at Dec. 31	**2021**		2020	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)[(1)]	—	—	95	—

(1) Excludes the long-term power sale - US contract. For further details on this contract, refer to Note 15(B)(I)(c)(i).

During 2021, unrealized pre-tax losses of $1 million (2020 — $1 million gains, 2019 — $1 million gains) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management – Non-Hedges

The Company's outstanding commodity derivative instruments not designated as hedging instruments are as follows:

As at Dec. 31	**2021**		2020	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity (MWh)	**46,139**	**14,951**	12,944	8,258
Natural gas (GJ)	**7,501**	**173,898**	23,035	177,448
Transmission (MWh)	**37**	**1,097**	—	1,578
Emissions (MWh)	**445**	**2,030**	1,831	2,112
Emissions (tonnes)	**350**	**350**	2,160	2,365
Coal (tonnes)	**—**	**9,352**	—	9,078

b. Interest Rate Risk Management

Interest rate risk arises as the fair value of future cash flows from a financial instrument fluctuates because of changes in market interest rates. Changes in interest rates can impact the Company's borrowing costs. Changes in the cost of capital may also affect the feasibility of new growth initiatives.

The Company's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 3 per cent of the Company's debt as at Dec. 31, 2021 (2020 – 7 per cent). Interest rate risk is managed with the use of derivatives. The Company's outstanding interest rate derivative instruments are as follows:

In 2021, the Company had interest rate swap agreements in place with a notional amount of US$150 million (2020 — US$150 million) whereby the Company receives a variable rate of interest equal to the three-month LIBOR rate and pays interest at a fixed rate equal to 0.94 per cent (2020 — 0.94 per cent) on the notional amount. The swaps are being used to hedge interest rate exposure on a highly probable future US$400 million fixed rate debt issuance, expected to occur in 2022.

In 2021, the Company had bond lock agreements in place with a total notional amount of US$150 million (2020 — $75 million) whereby on the pricing date, if the difference between the underlying 1.375 per cent US Treasury bond (2020 — 5.75 per cent Government of Canada bond) and the forward bond yield (2020 — $150 million forward yield 1.20 per cent) is positive, the Company receives settlement. If the difference is negative, the Company pays settlement. The bond lock is being used to hedge interest rate exposure on a highly probable future US$400 million (2020 —$150 million) fixed rate debt issuance. The $75 million bond lock outstanding at Dec. 31, 2020, was settled in 2021.

There were no interest rate derivative instruments outstanding in 2019.

LIBOR 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 facility references LIBOR for US dollar drawings and Canadian Dollar Offer Rate ("CDOR") for Canadian dollar drawings, and includes appropriate fallback language to replace these benchmark rates if a benchmark transition event were to occur. Currently there are no drawings on the facility. The non-recourse bond references the three-month CDOR: however, only the six- and 12-month CDOR have been discontinued with no expectation to stop publishing other CDOR rates at this time.

In addition, the Company has interest rate swap agreements in place with a notional amount of US$150 million referencing the three-month LIBOR, expected to settle in the third quarter of 2022. The cessation date for three-month LIBOR is June 30, 2023.

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 (2020 — US$370 million).

ii. Cash Flow Hedges
The Company uses foreign exchange forward contracts to hedge a portion of its future foreign-denominated receipts and expenditures, and both foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge.

As at Dec. 31	**2021**			2020			
Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value liability	Maturity
Foreign exchange forward contracts - foreign-denominated receipts/expenditures							
CAD10	**USD8**	**—**	**2022**	CAD71	USD54	(2)	2021
AUD19	**USD14**	**—**	**2022**	—	—	—	—

iii. Non-Hedges
The Company also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	2021				2020			
	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								
	AUD28	**CAD26**	**(5)**	**2022-2025**	AUD197	CAD181	(14)	2021 - 2024
	USD271	**CAD357**	**8**	**2022-2025**	USD47	CAD72	9	2021 - 2024
					AUD4	USD3	—	2021
					CAD1	EUR1	—	2021
Foreign exchange forward contracts – foreign-denominated debt								
	CAD191	**USD150**	1	**2022**	CAD191	USD150	2	2022

iv. Impacts of currency rate risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Company's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cent (2020 — three cent, 2019 — three cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2021		2020		2019	
Currency	**Net earnings increase (decrease)(1)**	**OCI gain(1)(2)**	Net earnings decrease(1)	OCI gain(1)(2)	Net earnings decrease(1)	OCI gain(1)(2)
USD	**(13)**	**1**	(8)	1	(18)	2
AUD	**1**	**—**	(4)	—	(6)	—
Total	**(12)**	**1**	(12)	1	(24)	2

(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, 2021:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables(1,2)	89	11	**100**	**651**
Long-term finance lease receivable	100	—	**100**	**185**
Risk management assets(1)	86	14	**100**	**707**
Total				**1,543**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes loan receivable with a counterparty that has no external credit rating. Refer to Note 22 for further details.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables as well as incorporating forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Company did not have significant expected credit losses as at Dec. 31, 2021.

The Company's maximum exposure to credit risk at Dec. 31, 2021, 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, 2021, was $37 million (2020 — $22 million).

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

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

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

III. Liquidity Risk

Liquidity risk relates to the Company's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. As at Dec. 31, 2021, TransAlta maintains an investment grade rating from one credit rating agency and below investment grade ratings from two credit rating agencies. Between 2022 and 2024, the Company has approximately $1 billion of debt maturing, comprised of approximately $515 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments and the classification of the Kent Hills Wind LP bond as current.

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 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 is as follows:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Accounts payable and accrued liabilities	689	—	—	—	—	—	689
Long-term debt[1]							
Debentures	—	—	—	—	—	251	251
Senior Notes	511	—	—	—	—	383	894
Non-recourse — Hydro	—	45	—	—	—	—	45
Non-recourse — Wind & Solar	263	49	52	54	51	283	752
Non-recourse — Gas	44	45	47	59	61	855	1,111
Tax equity financing	15	15	14	14	15	68	141
Other	3	1	—	—	—	—	4
Exchangeable securities[2]	—	—	—	750	—	—	750
Commodity risk management (assets) liabilities	(45)	(35)	(117)	(95)	1	(2)	(293)
Other risk management (assets) liabilities	(2)	(3)	(3)	1	—	(1)	(8)
Lease liabilities[3]	(6)	4	3	3	3	93	100
Interest on long-term debt and lease liabilities[4]	149	120	115	109	104	787	1,384
Interest on exchangeable securities[2, 4]	53	53	62	—	—	—	168
Dividends payable	62	—	—	—	—	—	62
Total	**1,736**	**294**	**173**	**895**	**235**	**2,717**	**6,050**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025. Refer to Note 25 for further details.
(3) Lease liabilities include a lease incentive of $13 million expected to be received in 2022.
(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. 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					
	2022	2023	2024	2025	2026	2027 and thereafter
Cash flow hedges						
Foreign currency forward contracts						
Notional amount ($ millions)						
CAD/USD	8	—	—	—	—	—
AUD/USD	14	—	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7893	—	—	—	—	—
AUD/USD	0.7352	—	—	—	—	—
Commodity derivative instruments						
Electricity						
Notional amount (thousands MWh)	3,329	3,329	3,338	2,628	—	—
Average price ($ per MWh)	71.95	73.76	75.6	77.49	—	—

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, 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	**13 MMWh**	**285**	**Risk management assets**	**(181)**
Interest rate risk				
Cash flow hedges				
Interest rate swap	**USD300**	**3**	**Risk management assets**	**3**
Foreign currency risk				
Cash flow hedges				
Foreign-denominated expenditures	**USD8**	**—**	**Risk management assets**	**—**
Foreign-denominated expenditures	**USD14**	**—**	**Risk management assets**	**—**
Net investment hedges				
Foreign-denominated debt	**USD370**	**CAD473**	**Credit facilities, long-term debt and lease liabilities**	**—**

As at Dec. 31, 2020	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	16 MMWh	573	Risk management assets	(33)
Interest rate risk				
Cash flow hedges				
Interest rate swap	USD150	(3)	Risk management liabilities	3
Interest rate swap	CAD75	(4)	Risk management liabilities	4
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD472	Credit facilities, long-term debt and lease liabilities	11

The impact of the hedged items on the statement of financial position is as follows:

As at Dec. 31	2021		2020	
	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	**(181)**	**226**	(33)	417
Interest rate risk				
Cash flow hedges				
Interest expense on long-term debt	**3**	**2**	7	19
	Change in fair value used for measuring ineffectiveness	**Foreign currency translation reserve[(1)]**	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve[(1)]
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**—**	**(35)**	11	(21)

(1) Included in AOCI.

The hedging 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 hedged items designated in hedging relationships on OCI and net earnings is:

		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**	**—**

Over the next 12 months, the Company estimates that approximately $25 million of after-tax gain 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, 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	—

	Year ended Dec. 31, 2019				
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	77	Revenue	(59)	Revenue	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	77	OCI impact	(53)	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2021, the Company recognized a net unrealized gain of $97 million (2020 — gain of $43 million, 2019 — gain of $33 million) related to commodity derivatives.

For the year ended Dec. 31, 2021, a gain of $6 million (2020 — gain of $11 million, 2019 —gain of $24 million) related to foreign exchange and other derivatives was recognized, which consists of net unrealized gains of $4 million (2020 — loss of $2 million, 2019 — gain of $6 million) and net realized gains of $2 million (2020 — gains of $13 million, 2019 — gains of $18 million), respectively.

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2021, the Company provided $55 million (2020 – $49 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2021, the Company held $18 million (2020 – nil) 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 included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the 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.

As at Dec. 31, 2021, the Company had posted collateral of $356 million (2020 – $163 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Company having to post an additional $120 million (2020 – $85 million) of collateral to its counterparties.

17. Inventory

The components of inventory are as follows:

As at Dec. 31	2021	2020
Parts and materials	**82**	107
Coal	**27**	83
Deferred stripping costs	**—**	8
Natural gas	**3**	2
Purchased emission credits(1)	**55**	38
Total	**167**	238

(1) Purchased emissions credits increased due to trading and compliance credits purchased, including those for Alberta compliance under the Technology Innovation and Emissions Reduction program.

No inventory is pledged as security for liabilities.

Carbon compliance costs are regulated costs that the business incurs as a result of greenhouse gas emissions generated from our operating units. TransAlta's exposure to carbon compliance costs is mitigated through the use of eligible emission credits generated from the Company's Wind and Solar and Hydro segments, as well as, purchasing emission credits from the market at prices lower than the regulated compliance price of carbon. Emission credits generated from our Alberta business have no recorded book value but are expected to be used to offset emission obligations from our gas facilities located in Canada in the future when the compliance price of carbon is expected to increase, resulting in a reduced cash cost for carbon compliance. At Dec. 31, 2021, the Company currently holds 2,033,752 purchased emission credits (2020 — 1,434,761) recorded at $55 million (2020 — $38 million) and approximately 1,922,973 (2020 — 1,211,230) emission credits with no recorded book value.

The change in inventory is as follows:

	2021	2020
Balance, Jan. 1	**238**	251
Net additions (use)	**22**	26
Write-downs, coal	**(65)**	(37)
Write-downs, parts and materials	**(28)**	—
Change in foreign exchange rates	**—**	(2)
Balance, Dec. 31	**167**	238

With the decision in 2020 to adjust the useful life of the Highvale mine assets to align with the Company's conversion to gas plans, the standard cost of coal increased during 2021 and 2020 as a result of increased depreciation costs and reduced coal consumption. During the same period, as the cost of the coal was not expected to be recovered based on power pricing, the Company recognized a $65 million (2020 — $37 million) write-down to net realizable value on its internally produced coal inventory for the year ended Dec. 31, 2021, of which $48 million relates to increased depreciation from the accelerated closure of the mine.

In addition, OM&A costs included a write-down of $28 million, for parts and material inventory related to the Highvale mine and coal operations at our natural gas converted facilities. With the accelerated shutdown of the Highvale mine and full conversion to natural gas completed in 2021. It was determined that a portion of the coal-related parts and materials inventory would not be utilized in the operations of our converted natural gas facilities and therefore the value was adjusted down to the expected net realizable amounts for the end of 2021.

18. Property, Plant and Equipment

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

	Land	Renewable generation	Gas generation[1]	Energy Transition[1]	Assets under construction	Capital spares and other[2]	Total
Cost							
As at Dec. 31, 2019, as previously reported	91	3,574	1,671	7,342	228	489	13,395
Adjustments due to re-segmentation	—	—	2,402	(2,402)	—	—	—
As at Dec 31, 2019, adjusted	91	3,574	4,073	4,940	228	489	13,395
Additions	—	—	—	—	478	8	486
Acquisitions (Note 4)	—	—	1	—	—	—	1
Disposals	(2)	—	—	(1)	—	(2)	(5)
Impairment (Note 7)	(9)	(2)	—	(69)	—	(1)	(81)
Revisions and additions to decommissioning and restoration costs (Note 23)	—	8	1	85	—	—	94
Retirement of assets	—	(7)	(47)	(3)	—	(1)	(58)
Change in foreign exchange rates	(1)	(14)	45	(39)	—	6	(3)
Transfers	17	33	(138)	(12)	(211)	(120)	(431)
As at Dec. 31, 2020, adjusted	96	3,592	3,935	4,901	495	379	13,398
Additions	**—**	**—**	**—**	**—**	**478**	**2**	**480**
Acquisitions (Note 4)	**—**	**146**	**—**	**—**	**—**	**—**	**146**
Disposals	**(1)**	**—**	**(2)**	**(74)**	**(2)**	**—**	**(79)**
Impairment (Note 7)	**—**	**(15)**	**(2)**	**(468)**	**(91)**	**(13)**	**(589)**
Revisions and additions to decommissioning and restoration costs (Note 23)	**—**	**129**	**6**	**—**	**—**	**—**	**135**
Retirement of assets	**—**	**(15)**	**(57)**	**(49)**	**—**	**—**	**(121)**
Change in foreign exchange rates	**—**	**3**	**(25)**	**2**	**—**	**(6)**	**(26)**
Transfers	**1**	**303**	**232**	**201**	**(696)**	**4**	**45**
As at Dec. 31, 2021	**96**	**4,143**	**4,087**	**4,513**	**184**	**366**	**13,389**
Accumulated depreciation							
As at Dec. 31, 2019, as previously reported	—	1,284	900	4,836	—	168	7,188
Adjustments due to re-segmentation	—	—	1,137	(1,137)	—	—	—
As at Dec 31, 2019, adjusted	—	1,284	2,037	3,699	—	168	7,188
Depreciation	—	141	258	304	—	14	717
Retirement of assets	—	(5)	(43)	(3)	—	—	(51)
Disposals	—	—	—	(1)	—	(1)	(2)
Change in foreign exchange rates	—	(4)	18	(37)	—	2	(21)
Transfers	—	—	(212)	(29)	—	(14)	(255)
As at Dec. 31, 2020, adjusted	—	1,416	2,058	3,933	—	169	7,576
Depreciation	**—**	**154**	**184**	**264**	**—**	**12**	**614**
Retirement of assets	**—**	**(9)**	**(55)**	**(48)**	**—**	**—**	**(112)**
Disposals	**—**	**—**	**(1)**	**(72)**	**—**	**—**	**(73)**
Change in foreign exchange rates	**—**	**—**	**(8)**	**2**	**—**	**(1)**	**(7)**
Transfers	**—**	**—**	**—**	**71**	**—**	**—**	**71**
As at Dec. 31, 2021	**—**	**1,561**	**2,178**	**4,150**	**—**	**180**	**8,069**
Carrying amount							
As at Dec. 31, 2019, adjusted	91	2,290	2,036	1,241	228	321	6,207
As at Dec. 31, 2020, adjusted	96	2,176	1,877	968	495	210	5,822
As at Dec. 31, 2021	**96**	**2,582**	**1,909**	**363**	**184**	**186**	**5,320**

(1) The gas generation and energy transition includes the previously disclosed coal generation and mining property and equipment categories.
(2) Includes major spare parts and stand-by equipment available, but not in service and spare parts used for routine, preventive or planned maintenance.

A. Renewable Generation

During 2021, the Company acquired North Carolina Solar (Refer to Note 4 for further details).

During the third quarter of 2021, Kent Hills 2 had a tower collapse resulting in an impairment of $2 million. Following extensive independent engineering assessments and root cause failure analysis, the Company announced on Jan. 11, 2022, that all 50 turbine foundations at the Kent Hills 1 and Kent Hills 2 sites require a full foundation replacement. As the turbines will not be returning to service until the foundations are replaced, the foundations were written off, resulting in an increase in depreciation of $12 million.

Transfers from assets under construction in 2021 are related to the Windrise wind facility of $255 million, Kent Hills wind rehabilitation project of $7 million and the balance is related to other wind and hydro facilities. Transfers between the classifications of PP&E in 2020 relate to the WindCharger project and planned major maintenance.

B. Gas Generation

During 2021, the Company completed the full conversion of Keephills Unit 2, Keephills Unit 3 and Sundance Unit 6 from thermal coal to natural gas. Transfers from assets under construction of $200 million relates to the planned coal to gas conversions and the balance is related to the Australian and US gas facilities.

During 2019, the sale of Genesee 3 resulted in a gain of $77 million, which was recognized in gains on sale of assets and other on the statement of earnings during the fourth quarter.

Transfers out of PP&E in 2020 mainly relate to removing the Southern Cross assets from PP&E to a finance lease receivable and moving the Pioneer Pipeline and mine equipment to assets held for sale. Transfers between the classifications of PP&E in 2020 relate to the Sundance Unit 6 conversion to gas.

C. Energy Transition Generation

Keephills Unit 1, Sundance Unit 5 and Sundance Unit 3 were retired from service effective Dec. 31, 2021, Nov. 1, 2021, and July 31, 2020, respectively. Sundance Unit 4 will be retired effective April 1, 2022. During 2021, the Company sold equipment related to coal generation that resulted in a gain of sale of $23 million. Centralia Unit 1 was retired from service effective Dec. 31, 2020, as originally planned.

Transfers from assets under construction in 2021 are mainly related to Keephills Unit 1 of $20 million, Sundance Unit 5 of $78 million and the mining property and equipment related to SunHills and Centralia of $100 million. The Company transferred certain generation assets from the Energy Transition segment to assets held for sale as a result of its assessment under IFRS 5 — *Non-current Assets Held for Sale and Discontinued Operations.* As part of this review there were no impairment charges recognized against the carrying value of $25 million. Transfers between the classifications of PP&E in 2020 relate to the Centralia land purchase.

During the third quarter of 2020, the Board approved the accelerated shutdown of the Highvale mine by the end of 2021 and accordingly the useful life of the related assets was adjusted to align with the Company's conversion to gas plans. This resulted in an increase of $15 million in depreciation expense that was recognized in the Consolidated Statements of Earnings (Loss) during the second half of 2020.

D. Assets Under Construction

Initial construction activities on the Garden Plain wind project started in the third quarter of 2021. In addition, the Company commenced construction in the fourth quarter of 2021 on the Northern Goldfields Solar Project. The Northern Goldfields Solar Project comprises the 27 MW Mount Keith Solar Farm, 11 MW Leinster Solar Farm, 10MW/5MWh Leinster battery energy storage system and interconnecting transmission infrastructure, all of which will be integrated into our existing 169 MW Southern Cross Energy North remote network in Western Australia. Upon completion of construction, these will be transferred to finance lease receivables.

Additions in 2021 are related to the Windrise wind project of $96 million (2020 — $156 million), White Rock Wind Projects of $32 million (2020 — nil), Garden Plain wind project of $38 million (2020 — nil), the Kaybob cogeneration project of $14 million (2020 — $31 million), coal to gas conversions of $91 million (2020 — $93 million) and planned major maintenance expenditures. In 2020, the additions included the WindCharger battery storage project of $6 million and Centralia mine land of $17 million.

Transfers out to assets held for sale include $25 million related to salvage values for Sundance Unit 5 repowering project.

In 2021, the Company capitalized $14 million (2020 — $8 million) of interest to PP&E in at a weighted average rate of 6.0 per cent (2020 — 6.0 per cent).

19. 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, 2019	58	16	2	25	45	146
Additions	3	13	—	—	—	16
Depreciation	(3)	(5)	(1)	(9)	(3)	(21)
As at Dec. 31, 2020	58	24	1	16	42	141
Additions	**—**	**1**	**—**	**—**	**—**	**1**
Acquisitions (Note 4)	**13**	**—**	**—**	**—**	**—**	**13**
Depreciation	**(3)**	**(5)**	**—**	**(2)**	**(1)**	**(11)**
Disposal of assets (Note 4)	**—**	**—**	**—**	**—**	**(41)**	**(41)**
Transfers	**—**	**—**	**—**	**(8)**	**—**	**(8)**
As at Dec. 31, 2021	**68**	**20**	**1**	**6**	**—**	**95**

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, 2021, TransAlta paid $15 million (2020 — $33 million) related to recognized lease liabilities, consisting of $7 million in interest (2020 — $8 million) and $8 million (2020 — $25 million) in principal repayments.

Short-term leases (term of less than 12 months) and leases with total lease payments below the Company's capitalization threshold do not require recognition as lease liabilities and right-of-use assets.

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, 2021, the Company expensed $6 million (2020 — $7 million) in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 11, 24 and 36.

20. Intangible Assets

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Power sale contracts	Software and other	Intangibles under development	Coal rights	Total
Cost					
As at Dec. 31, 2019	250	378	11	149	788
Additions	—	—	14	—	14
Acquisition (Note 4)	37	—	—	—	37
Disposals	—	(1)	—	—	(1)
Change in foreign exchange rates	(2)	—	—	—	(2)
Transfers	(16)	35	(22)	—	(3)
As at Dec. 31, 2020	269	412	3	149	833
Additions	**—**	**—**	**9**	**—**	**9**
Impairment (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**
Accumulated amortization					
As at Dec. 31, 2019	107	246	—	117	470
Amortization	15	28	—	8	51
Disposals	—	(1)	—	—	(1)
Transfers	1	(1)	—	—	—
As at Dec. 31, 2020	123	272	—	125	520
Amortization	**17**	**27**	**—**	**7**	**51**
As at Dec. 31, 2021	**140**	**299**	**—**	**132**	**571**
Carrying amount					
As at Dec. 31, 2019	143	132	11	32	318
As at Dec. 31, 2020	146	140	3	24	313
As at Dec. 31, 2021	**129**	**123**	**4**	**—**	**256**

21. Goodwill

Goodwill acquired through business combinations has been allocated to CGUs that are expected to benefit from the synergies of the acquisitions. Goodwill by segments are as follows:

As at Dec. 31	**2021**	2020
Hydro	**258**	258
Wind and Solar	**175**	175
Energy Marketing	**30**	30
Total goodwill	**463**	463

For the purposes of the 2021 goodwill impairment review, the Company determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections based on the Company's long-range forecasts for the period extending to the last planned asset retirement in 2052. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. In 2021, the Company relied on the recoverable amounts determined in 2019 for the Hydro and Energy Marketing segments in performing the 2021 goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumptions impacting the determination of fair value for the Wind and Solar and Hydro segments are the following:

- Discount rates used for the goodwill impairment calculation in 2021 for the Wind and Solar segment ranged from 5.0 per cent to 6.4 per cent (2020 – 4.8 per cent to 6.3 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. Electricity prices used in these 2021 models ranged between $17 to $136 per MWh during the forecast period (2020 – $6 to $160 per MWh).

22. Other Assets

The components of other assets are as follows:

As at Dec. 31	**2021**	2020
South Hedland prepaid transmission access and distribution costs	**65**	70
Project development costs	**29**	25
Long-term prepaids and other assets	**48**	59
Loan receivable	**55**	52
Total other assets	**197**	206
Included in the Consolidated Statements of Financial Position as:		
Total current other assets (Note 14)	**55**	—
Total long-term other assets	**142**	206
Total other assets	**197**	206

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.

Project development costs primarily include the project costs for US wind and Australian development projects. Some project costs were written off in 2021 due to the uncertainty on timing of when the projects will proceed (see Note 7).

Long-term prepaids and other assets includes: the funded portion of rail transportation commitments discussed in Note 36(C), the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 36(G) and other contractually required prepayments and deposits.

The loan receivable relates to the advancement by the Company's subsidiary, Kent Hills Wind LP, of $55 million (2020 – $52 million) which is net of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The unsecured loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017 and matures in October 2022; as such, it was moved to current assets (Note 14).

23. Decommissioning and Other Provisions

The change in decommissioning and other provision balances is as follows:

	Decommissioning and restoration	Other provisions	Total
Balance, Dec. 31, 2019	501	45	546
Liabilities incurred	1	34	35
Liabilities settled	(18)	(19)	(37)
Accretion	30	—	30
Acquisition of liabilities	1	—	1
Revisions in estimated cash flows	61	11	72
Revisions in discount rates[1]	36	—	36
Reversals	—	(6)	(6)
Change in foreign exchange rates	(4)	—	(4)
Balance, Dec. 31, 2020	608	65	673
Liabilities incurred	**8**	**22**	**30**
Liabilities settled (Note 36)	**(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**

(1) Discount rates at Dec. 31, 2020, are generally lower than those at Dec. 31, 2019, due to decreases in the underlying risk-free US and Canadian benchmark yields and changes in credit spreads due to volatility within the market as a result of COVID-19. On average, these rates decreased by approximately 0.3 to 0.9 per cent.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2020	608	65	673
Current portion	21	38	59
Non-current portion	587	27	614
Balance, Dec. 31, 2021	**793**	**34**	**827**
Current portion	**35**	**13**	**48**
Non-current portion	**758**	**21**	**779**

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 2022 and 2072. The majority of the costs will be incurred between 2025 and 2050.

In 2021, the Company adjusted the wind assets decommissioning and restoration provision as estimates were updated after the review of a recent engineering study on the decommissioning costs of the wind sites. The Company's current best estimate of the decommissioning and restoration provision increased by $120 million. The change in estimate is unrelated to the tower failure identified in the fourth quarter of 2021. The Company also increased the decommissioning and restoration provision by approximately $47 million for the Sundance and Keephills Units included in the Gas and Energy Transition segments to reflect the change in the timing of the expected reclamation work resulting from asset retirements and change in useful lives. These changes resulted in an increase in the related assets in PP&E.

At Dec. 31, 2021, the Company had provided a surety bond in the amount of US$147 million (2020 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2021, the Company had provided letters of credit in the amount of $188 million (2020 – $131 million) in support of future decommissioning obligations at the Highvale mine.

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

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

B. Other Provisions

Other provisions also include provisions arising from ongoing business activities and include amounts related to commercial disputes between the Company and customers or suppliers. Information about the expected timing of settlement and uncertainties that could impact the amount or timing of settlement has not been provided as this may impact the Company’s ability to settle the provisions in the most favourable manner.

During the third quarter of 2021, an onerous contract provision for future royalty payments of $14 million was recognized as a result of a decision to accelerate the plans to shut down the Highvale mine, with the effect that any remaining future royalty payments related to the extraction of coal has no future economic benefit. Payments required under the royalty contract will continue through 2023. At Dec. 31, 2021, the remaining balance of the provision was $14 million.

During the fourth quarter of 2020, an onerous contract provision of $29 million was recognized as a result of a decision to accelerate plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021. The last coal shipment was received during the first quarter of 2021, while payments required under the contract will continue until 2025. At Dec. 31, 2021, the remaining balance of the provision was $14 million.

24. Credit Facilities, Long-Term Debt and Lease Liabilities

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31				2021			2020		
	Segment	Maturity	Currency	Carrying value	Face value	Interest[1]	Carrying value	Face value	Interest
Credit facilities									
Committed syndicated bank facility[2]	Corporate	2025	CAD	**—**	**—**	**—%**	114	114	2.7%
Debentures									
7.3% Medium term notes	Corporate	2029	CAD	**110**	**110**	**7.3%**	109	110	7.3%
6.9% Medium term notes	Corporate	2030	CAD	**141**	**141**	**6.9%**	140	141	6.9%
Senior notes[3]									
6.5% Senior notes	Corporate	2040	USD	**378**	**383**	**6.5%**	380	383	6.5%
4.5% Senior notes	Corporate	2022	USD	**510**	**511**	**4.5%**	506	511	4.5%
Non-recourse									
Melancthon Wolfe Wind LP bond	Wind & Solar	2028	CAD	**235**	**237**	**3.8%**	268	270	3.8%
New Richmond Wind LP bond	Wind & Solar	2032	CAD	**120**	**121**	**4.0%**	127	128	4.0%
Kent Hills Wind LP bond[4]	Wind & Solar	2033	CAD	**221**	**221**	**4.5%**	230	233	4.5%
Windrise Wind LP bond	Wind & Solar	2041	CAD	**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	**102**	**104**	**4.4%**	111	113	4.5%
TEC Hedland PTY Ltd bond[5]	Gas	2042	AUD	**732**	**742**	**4.1%**	772	782	4.1%
TransAlta OCP LP bond	Gas	2030	CAD	**263**	**265**	**4.5%**	284	287	4.5%
Tax equity financing									
Big Level & Antrim[6]	Wind & Solar	2029	USD	**106**	**112**	**6.6%**	112	119	6.6%
Lakeswind[7]	Wind & Solar	2029	USD	**18**	**18**	**10.5%**	22	22	10.5%
North Carolina Solar[8]	Wind & Solar	2028	USD	**11**	**11**	**7.3%**	—	—	—
Other	Corporate	2023	CAD	**4**	**4**	**5.9%**	7	6	5.9%
Total long-term debt				**3,167**	**3,198**		3,227	3,264	
Lease liabilities				**100**			134		
				3,267			3,361		
Less: current portion of long-term debt				**(837)**			(97)		
Less: current portion of lease liabilities				**(7)**			(8)		
Total current long-term debt and lease liabilities				**(844)**			(105)		
Total credit facilities, long-term debt and lease liabilities				**2,423**			3,256		

(1) Interest 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, 2021 — US$700 million (Dec. 31, 2020 — US$700 million).
(4) Kent Hills Wind LP bond is classified as a current liability. Refer to section B - Restrictions Related to Non-Recourse Debt and Other Debt, for more information.
(5) AU face value at Dec. 31, 2021 — AU$800 million related to the TEC offering (2020 — AU$800 million).
(6) US face value at Dec. 31, 2021 — US$88 million (2020 — US$94 million).
(7) US face value at Dec. 31, 2021 — US$14 million (2020 — US$16 million).
(8) US face value at Dec. 31, 2021 — US$9 million (2020 — nil).

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

As at Dec. 31, 2021	Facility size	Utilized: Outstanding letters of credit[1]	Utilized: Actual drawings	Available capacity	Maturity date
TransAlta Corporation					
Committed syndicated bank facility[2]	1,250	618	—	632	Q2 2025
Canadian committed bilateral credit facilities	240	186	—	54	Q2 2023
TransAlta Renewables					
Committed credit facility[2]	700	98	—	602	Q2 2025
Total	**2,190**	**902**	**—**	**1,288**	

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2021, TransAlta provided cash collateral of $55 million.
(2) Includes letters of credit issued under the demand facilities for TransAlta and TransAlta Renewables.

The Company has $2 billion (2020 — $2 billion) of committed syndicated bank facilities and $0.2 billion of committed bilateral credit facilities, of which $1.3 billion was available as at Dec. 31, 2021 (2020 — $1.5 billion) and including the undrawn letters of credit are the primary source for short-term liquidity after the cash flow generated from the Company's business. This includes a $1.3 billion credit facility that was converted into a facility with a Sustainability Linked Loan ("SLL") and that was extended to June 30, 2025. The facility's financing terms will align the cost of borrowing to TransAlta's greenhouse gas emission reductions and gender diversity targets, which are part of the Company's overall plan for environment, social and governance. The SLL will have a cumulative pricing adjustment to the borrowing costs on the facilities and a corresponding adjustment to the standby fee (the "Sustainability Adjustment"). Depending on performance against interim targets that have been set for each year of the credit facility term, the Sustainability Adjustment is structured as a two-way mechanism and could move either up, down or remain unchanged for each sustainability performance target based on performance. In addition, the Company's committed bilateral credit facilities were also extended to June 30, 2023. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, USD LIBOR or US base rate – 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 $1.3 billion available under the credit facilities, the Company also has $947 million of available cash and cash equivalents 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 $157 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.

Debentures
On Nov. 25, 2020, the Company redeemed $400 million of its then due 5.0 per cent medium term notes.

Senior notes
A total of US$370 million (2020 — US$370 million) of the senior notes has been designated as a hedge of the Company’s net investment in US foreign operations.

Non-recourse debt
On Dec. 6, 2021, TransAlta completed a secured green bond offering by way of private placement for approximately $173 million (the "Offering"). The 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 intends to use proceeds of the Offering to finance or refinance eligible green projects, including renewable energy facilities and to fund a construction reserve account.

On Oct. 22, 2020, TEC closed an AU$800 million senior secured note offering, by way of a private placement, which is secured by, among other things, a first ranking charge over all assets of TEC. The notes bear interest at 4.07 per cent per annum, payable quarterly and matures on June 30, 2042, with principal payments starting on March 31, 2022. Funds were used to repay indebtedness on the credit facility and to fund future growth opportunities within TransAlta Renewables. The TEC Offering has a rating of BBB by Kroll Bond Rating Agency.

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 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 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 - on March 31, 2030, 10 years from commercial operation of the projects; Lakeswind - March 31, 2029, and North Carolina Solar on Dec. 31, 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, 2021, the Company was in compliance with all debt covenants except the Kent Hills non-recourse bond as discussed below.

B. Restrictions Related to Non-Recourse Debt and Other Debt

The Melancthon Wolfe Wind LP, Pingston, 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 $1.9 billion as at Dec. 31, 2021 (Dec. 31, 2020 — $1.8 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 2021, except the Kent Hills non-recourse bond as discussed below. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2022. At Dec. 31, 2021, $67 million (Dec. 31, 2020 —$73 million) of cash was subject to these financial restrictions. At Dec. 31, 2021, Kent Hills cash in the amount of $6 million is not able to be distributed or accessed by other corporate entities, as discussed below.

Proceeds received from the TEC Notes in the amount of $3 million (AU$4 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.

As a result of the determination that all 50 foundations require replacement, as well as certain resulting amendments to applicable insurance policies, the Company has provided notice to BNY Trust Company of Canada, as trustee (the "Trustee"), for the approximately $221 million outstanding non-recourse project bonds (the "KH Bonds") secured by, among other things, the Kent Hills 1, 2 and 3 wind sites, that events of default may have occurred under the trust indenture governing the terms of the KH Bonds. Upon the occurrence of any event of default, holders of more than 50 per cent of the outstanding principal amount of the KH Bonds have the right to direct the Trustee to declare the principal and interest on the KH Bonds and all other amounts due, together with any make-whole amount (Dec. 31, 2021 — $39 million), to be immediately due and payable and to direct the Trustee to exercise rights against certain collateral. The Company is in discussions with the Trustee and holders of the Kent Hills bonds to negotiate required waivers and amendments while the Company works to remedy the matters described in the notice. Although the Company expects that it will reach agreement with the Trustee and holders of the KH Bonds with respect to terms of an acceptable waiver and amendment, there can be no assurance that the Company will receive such waivers and amendments. Accordingly, the Company has classified the entire carrying value of the KH Bonds as a current liability as at Dec. 31, 2021.

C. Security

Non-recourse debts totalling $1.5 billion as at Dec. 31, 2021 (Dec. 31, 2020 — $1.4 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, 2021 (Dec. 31, 2020 — $1 billion) and intangible assets with total carrying amounts of $78 million (Dec. 31, 2020 — $88 million). At Dec. 31, 2021, a non-recourse bond of approximately $103 million (Dec. 31, 2020 — $111 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 $263 million (Dec. 31, 2020 — $285 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

	2022(1)	2023	2024	2025	2026	2027 and thereafter	Total
Principal repayments(2)	836	155	113	127	127	1,840	**3,198**
Lease liabilities(3)	(6)	4	3	3	3	93	**100**

(1) Includes the Kent Hills Wind LP non-recourse bonds. The successful receipt of waivers and amendments would extend principal repayments beyond 2022.
(2) Excludes impact of hedge accounting and derivatives.
(3) Lease liabilities include a lease incentive of $13 million, expected to be received in 2022.

E. Restricted Cash

At Dec. 31, 2021, the Company had nil (Dec. 31, 2020 – $9 million) in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds were released from the construction reserve account in 2021.

The Company had $17 million (Dec. 31, 2020 – $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2022.

The Company also had $53 million (Dec. 31, 2020 – $45 million) of restricted cash related to the TEC Notes; reserves are required to be held under TEC commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities and its two uncommitted $150 million and $100 million demand letters of credit facilities. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $150 million demand letter of credit 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, 2021, was $902 million (2020 – $621 million) with no (2020 – nil) amounts exercised by third parties under these arrangements.

25. 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").

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Company paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures.

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in exchange for redeemable, retractable first preferred shares.

A. $750 million Exchangeable Securities

As at	**Dec. 31, 2021**			Dec. 31, 2020		
	Carrying value	**Face value**	**Interest**	**Carrying value**	**Face value**	**Interest**
Exchangeable debentures – due May 1, 2039	**335**	**350**	**7%**	330	350	7%
Exchangeable preferred shares[1]	**400**	**400**	**7%**	400	400	7%
Total long-term debt	**735**	**750**		730	750	

(1) Exchangeable preferred share dividends are reported as interest expense.

On Dec. 13, 2021, 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, 2022. The Exchangeable Preferred Shares are considered debt for accounting purposes, and as such, dividends are reported as interest expense (Note 11).

B. Option to Exchange

As at	**Dec. 31, 2021**		Dec. 31, 2020	
Description	**Base fair value**	**Sensitivity**	**Base fair value**	**Sensitivity**
Option to exchange – embedded derivative	**—**	**+nil -32**	—	+nil -33

The Investment Agreement allows Brookfield the option, after Dec. 31, 2024, to exchange all of the outstanding exchangeable securities 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, 2021, Brookfield, through its affiliates, held, owned or had control over an aggregate of 35,425,696 common shares, representing approximately 13.1 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.

26. Defined Benefit Obligation and Other Long-Term Liabilities

The components of defined benefit obligation and other long-term liabilities are as follows:

As at Dec. 31	2021	2020
Defined benefit obligation (Note 31)	**228**	282
Long-term incentive accruals (Note 30)	**4**	4
Other	**21**	12
Total	**253**	298

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. As a result of increases in discount rates in 2021, largely driven by increases in market benchmark rates, the defined benefit obligation has decreased by $54 million to $228 million as at Dec. 31, 2021, from $282 million as at Dec. 31, 2020.

27. Common Shares

A. Issued and Outstanding

TransAlta is authorized to issue an unlimited number of voting common shares without nominal or par value.

As at Dec. 31	2021		2020	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**269.8**	**2,896**	277.0	2,978
Purchased and cancelled under the NCIB	**—**	**—**	(7.3)	(79)
Effects of share-based payment plans	**—**	**(3)**	—	(3)
Stock options exercised	**1.2**	**8**	0.1	—
Issued and outstanding, end of year	**271.0**	**2,901**	269.8	2,896

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	2021	2020
Total shares purchased[1]	**—**	7,352,600
Average purchase price per share	**—**	$8.33
Total cost	**—**	61
Weighted average book value of shares cancelled	**—**	79
Amount recorded in deficit	**—**	18

(1) As at Dec. 31, 2021, includes nil (2020 — 456,200) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

2021

On May 25, 2021, the Toronto Stock Exchange ("TSX") accepted the notice filed by the Company to implement an NCIB for a portion of our 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 18, 2021. 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, 2021 and ends on May 30, 2022, 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. No common shares have been repurchased under the current and previous NCIB in 2021.

2020

On May 26, 2020, 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, the Company was permitted to purchase up to a maximum of 14,000,000 common shares, representing approximately 7.02 per cent of its issued and common shares as at May 25, 2020.

C. Shareholder Rights Plan

The Company initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019, to reflect current market practice and to reflect changes to the take-over bid regime. As required, the Shareholder Rights Plan must be put before the Company's shareholders every three years for approval. It was last approved on April 26, 2019, and will need to be approved at the annual meeting of shareholders in 2022. 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	**2021**	2020	2019
Net earnings (loss) attributable to common shareholders	**(576)**	(336)	52
Basic and diluted weighted average number of common shares outstanding (millions)	**271**	275	283
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(2.13)**	(1.22)	0.18

E. Dividends

On Dec. 13, 2021, the Company declared a quarterly dividend of $0.05 per common share, payable on April 1, 2022.

There have been no other transactions involving common shares between the reporting date and the date of completion of these consolidated financial statements.

28. Preferred Shares

A. Issued and Outstanding

All preferred shares issued and outstanding are non-voting cumulative redeemable fixed or floating rate first preferred shares.

As at Dec. 31	2021		2020	
Series	**Number of shares** *(millions)*	**Amount**	Number of shares *(millions)*	Amount
Series A	**9.6**	**235**	10.2	248
Series B	**2.4**	**58**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares Conversion

On March 18, 2021, the Company announced that 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") were tendered for conversion, on a one-for-one basis, into Series B Shares and Series A Shares, respectively after having taken into account all election notices. As a result of the conversion, the Company had 9.6 million Series A Shares and 2.4 million Series B Shares issued and outstanding at March 31, 2021.

II. Preferred Share Series Information

The holders are entitled to receive cumulative fixed quarterly cash dividends at a specified rate, as approved by the Board. After an initial period of approximately five years from issuance and every five years thereafter ("Rate Reset Date"), the fixed rate resets to the sum of the then five-year Government of Canada bond yield (the fixed rate "Benchmark") plus a specified spread. Upon each Rate Reset Date, the shares are also:

- Redeemable at the option of the 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, 2021, are as follows:

Series	**Rate during term**	**Annual dividend rate per share** *($)*	**Next conversion date**	**Rate spread over benchmark** *(per cent)*	**Convertible to Series**
A	Fixed	0.71924	March 31, 2026	2.03	B
B	Floating	0.53866	March 31, 2026	2.03	A
C	Fixed	1.00676	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29852	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.24700	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of the preferred share dividends declared in 2021 and 2020:

	Total dividends declared	
Series	**2021[1]**	2020
A	**7**	9
B[2]	**1**	1
C	**11**	14
E	**12**	15
G	**8**	10
Total for the year	**39**	49

(1) No dividends were declared in the first quarter of 2021 as the quarterly dividend related to the period covering the first quarter of 2021 was declared in December 2020.
(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

On Dec. 13, 2021, the Company declared a quarterly dividend of $0.1798 per share on the Series A preferred shares, $0.1331 per share on the Series B preferred shares, $0.2517 per share on the Series C preferred shares, $0.3246 per share on the Series E preferred shares, and $0.3118 per share on the Series G preferred shares, all payable on March 31, 2022.

29. Accumulated Other Comprehensive Earnings

The components of, and changes in, accumulated other comprehensive earnings are as follows:

	2021	2020
Currency translation adjustment		
Opening balance, Jan. 1	**(21)**	(21)
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(14)**	(11)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**—**	11
Balance, Dec. 31	**(35)**	(21)
Cash flow hedges		
Opening balance, Jan. 1	**436**	527
Losses on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax[1]	**(208)**	(91)
Balance, Dec. 31	**228**	436
Employee future benefits		
Opening balance, Jan. 1	**(66)**	(55)
Net actuarial gains (losses) on defined benefit plans, net of tax[2]	**37**	(11)
Balance, Dec. 31	**(29)**	(66)
Other		
Opening balance, Jan. 1	**(47)**	3
Intercompany investments at FVOCI	**29**	(50)
Balance, Dec. 31	**(18)**	(47)
Accumulated other comprehensive earnings	**146**	302

(1) Net of income tax of $57 million for the year ended Dec. 31, 2021 (2020 — $23 million).
(2) Net of income tax of $11 million for the year ended Dec. 31, 2021 (2020 — $3 million).

30. 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 PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Company's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the 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 2021 was $14 million (2020 – $15 million, 2019 – $19 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the 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 DSUs was $3 million in 2021 (2020 – $1 million, 2019 – $2 million).

C. Stock Option Plans

On May 4, 2021, the Company 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 (Dec. 31, 2020 — 16.5 million common shares). 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 plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2021, the Company granted executive officers of the Company a total of 0.7 million stock options with a weighted average exercise price of $9.86 that vest after a three-year period and expire seven years after issuance (2020 — 0.7 million stock options at $9.17; 2019 — 1.4 million stock options at $5.65). The expense recognized relating to these grants during 2021 was approximately $2 million (2020 — approximately $2 million, 2019 — approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2021, are outlined below:

	Options outstanding		
Range of exercise prices[(1)] *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 9.00	**3.2**	**4.2**	**7.54**

(1) Options currently exercisable as at Dec. 31, 2021.

31. 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, 2021. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2019. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2021.

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 2021 for the amount of $97 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, 2019, and Jan. 1, 2021, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2021.

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 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

The costs recognized in net earnings during the year on the defined benefit, defined contribution and other post-employment benefits plans are as follows:

Year ended Dec. 31, 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

Year ended Dec. 31, 2019	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	–	–	2
Interest cost on defined benefit obligation	19	3	1	23
Interest on plan assets	(12)	(1)	–	(13)
Curtailment and amendment gain	(3)	–	–	(3)
Defined benefit expense	13	4	2	19
Defined contribution expense	9	–	–	9
Net expense	22	4	2	28

C. Status of Plans

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

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)**

Year ended Dec. 31, 2020	Registered	Supplemental	Other	Total
Fair value of plan assets	367	14	–	381
Present value of defined benefit obligation	(542)	(109)	(24)	(675)
Funded status – plan deficit	(175)	(95)	(24)	(294)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(5)	(5)	(2)	(12)
Other long-term liabilities	(170)	(90)	(22)	(282)
Total amount recognized	(175)	(95)	(24)	(294)

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, 2019	373	13	–	386
Interest on plan assets	11	1	–	12
Net return on plan assets	25	(1)	–	24
Contributions	6	6	1	13
Benefits paid	(45)	(5)	(1)	(51)
Administration expenses	(1)	–	–	(1)
Effect of translation on US plans	(2)	–	–	(2)
As at Dec. 31, 2020	367	14	–	381
Interest on plan assets	**8**	**–**	**–**	**8**
Net return 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**

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

Year ended 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**

Year ended Dec. 31, 2020	Level I	Level II	Level III	Total
Equity securities				
Canadian	–	64	–	64
US	–	30	–	30
International	–	103	–	103
Private	–	–	1	1
Bonds				
AAA	–	36	–	36
AA	–	67	–	67
A	–	34	–	34
BBB	1	22	–	23
Below BBB	–	4	–	4
Money market and cash and cash equivalents	–	19	–	19
Total	1	379	1	381

Plan assets do not include any common shares of the Company at Dec. 31, 2021 and Dec. 31, 2020. The Company charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2021 (2020 – nil).

E. Defined Benefit Obligation

The present value of the obligation for the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2019	543	99	22	664
Current service cost	5	2	1	8
Interest cost	16	3	1	20
Benefits paid	(45)	(5)	(1)	(51)
Curtailment	(2)	—	—	(2)
Actuarial loss arising from financial assumptions	43	10	2	55
Actuarial gain arising from experience adjustments	(17)	—	—	(17)
Effect of translation on US plans	(1)	—	(1)	(2)
Present value of defined benefit obligation as at Dec. 31, 2020	542	109	24	675
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**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2021, is 13.6 years.

F. Contributions

The expected employer contributions for 2022 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**6**	**2**	**13**

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:

	As at Dec. 31, 2021			As at Dec. 31, 2020		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
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(1)(3)	**—**	**—**	**6.8**	—	—	6.8
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**2.4**	**2.3**	**2.3**	3.0	3.0	3.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.9	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.1**	—	—	7.1
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0

(1) 2021 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(2) 2021 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(3) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(4) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.

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, 2021	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**61**	**15**	**2**	**3**	**1**
1% increase in the salary scale	**3**	**—**	**—**	**—**	**—**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**4**	**—**	**1**	**—**

32. Joint Arrangements

Joint arrangements at Dec. 31, 2021, 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

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	**2021**	2020	2019
(Use) source:			
Accounts receivable	**(28)**	(79)	261
Prepaid expenses	**9**	2	—
Income taxes receivable	**—**	(4)	(6)
Inventory	**42**	6	(13)
Accounts payable, accrued liabilities and provisions	**153**	160	(130)
Income taxes payable	**(2)**	4	9
Change in non-cash operating working capital	**174**	89	121

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2020	**Cash issuances**	**Repayments and dividends paid**	**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**

	Balance Dec. 31, 2019	Cash issuances	Repayments and dividends paid	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2020
Long-term debt and lease liabilities	3,212	753	(620)	16	—	5	(5)	3,361
Exchangeable securities	326	400	—	—	—	—	4	730
Dividends payable (common and preferred)	37	—	(86)	—	107	—	1	59
Total liabilities from financing activities	3,575	1,153	(706)	16	107	5	—	4,150

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2021	2020	Increase/ (decrease)
Long-term debt[(1)]	**3,267**	3,361	**(94)**
Exchangeable securities	**735**	730	**5**
Equity			
Common shares	**2,901**	2,896	**5**
Preferred shares	**942**	942	**—**
Contributed surplus	**46**	38	**8**
Deficit	**(2,453)**	(1,826)	**(627)**
Accumulated other comprehensive earnings	**146**	302	**(156)**
Non-controlling interests	**1,011**	1,084	**(73)**
Less: available cash and cash equivalents[(2)]	**(947)**	(703)	**(244)**
Less: principal portion of restricted cash on TransAlta OCP bonds[(3)]	**(17)**	(11)	**(6)**
Less: fair value asset of hedging instruments on long-term debt[(4)]	**(2)**	(2)	**—**
Total capital	**5,629**	6,811	**(1,182)**

(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 because 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 its 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 (stable outlook). During 2021, Moody's reaffirmed its issuer rating of Ba1 with a stable outlook; DBRS reaffirmed the Company's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Company's Unsecured Debt rating and Issuer 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, 2021 and 2020, 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 is available to fund operations, pay dividends, distribute payments to subsidiaries' non-controlling interests and invest in PP&E.

Year ended Dec. 31	2021	2020	Increase (decrease)
Cash flow from operating activities	**1,001**	702	**299**
Change in non-cash working capital	**(174)**	(89)	**(85)**
Cash flow from operations before changes in working capital	**827**	613	**214**
Dividends paid on common shares	**(48)**	(47)	**(1)**
Dividends paid on preferred shares	**(39)**	(39)	**—**
Distributions paid to subsidiaries' non-controlling interests	**(156)**	(97)	**(59)**
Property, plant and equipment expenditures	**(480)**	(486)	**6**
Inflow (outflow)	**104**	(56)	**160**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2021, $1.3 billion (2020 – $1.5 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 to maintain its capital structure and credit metrics within targeted ranges.

35. Related-Party Transactions

Details of the Company's principal operating subsidiaries at Dec. 31, 2021, 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	2021	2020	2019
Total compensation	**30**	27	30
Comprised of:			
Short-term employee benefits	**14**	12	13
Post-employment benefits	**1**	2	2
Termination benefits	**—**	—	2
Share-based payments	**15**	13	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 North Carolina Solar 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 Dec. 23, 2020, TransAlta announced that it had entered into definitive agreements for the acquisition by TransAlta Renewables, a subsidiary of the Company, of its 100 per cent direct interest in the 206 MW Windrise wind project located in the Municipal District of Willow Creek, Alberta. On Feb. 26, 2021, TransAlta completed the sale of its 100 per cent direct interest in the 206 MW Windrise wind project to TransAlta Renewables, for $213 million.

WindCharger

On Aug. 1, 2020, the WindCharger battery storage project was sold to TransAlta Renewables for $12 million.

TEC Offering

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

36. 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:

	2022	2023	2024	2025	2026	2027 and thereafter	Total
Natural gas, transportation and other contracts	47	54	45	44	45	508	**743**
Transmission	9	9	6	6	2	—	**32**
Coal supply and mining agreements[1]	76	98	90	75	—	—	**339**
Long-term service agreements	89	46	43	32	25	54	**289**
Operating leases	4	3	3	1	1	31	**43**
Growth	941	276	—	—	—	—	**1,217**
TransAlta Energy Transition Bill	6	6	—	—	—	—	**12**
Total	**1,172**	**492**	**187**	**158**	**73**	**593**	**2,675**

(1) Relates to coal supply and mining agreements for Centralia Unit 2.

A. Natural Gas, Transportation and Other Contracts

The Company has fixed price or volume natural gas purchase and transportation contracts. Upon closing of the sale of the Pioneer Pipeline, additional 15-year natural gas transportation agreements for 275 terajoules ("TJ") per day on a firm basis by 2023 arose, bringing the total firm natural gas transportation to 400 TJ per day. Additionally, on June 30, 2021, the Company's agreement to purchase 139 TJ per day of natural gas from Tidewater Midstream & Infrastructure Ltd. was terminated and the commitment related to commodity dispatching was discharged, resulting in a reduction to the commitments disclosed at Dec. 31, 2020, by approximately $1.3 billion.

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 and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia thermal facility. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2025. Pricing is reflective of current market conditions.

Commitments related to mining agreements for the Company's share of its Sheerness joint operation have been reduced due to the accelerated plans to eliminate coal as a fuel source at the Sheerness facility. Amounts due under the contract and a mining royalty agreement for the Highvale mine have been recognized as onerous contract provisions, with the result that no amounts are included as future commitments. For additional information refer to Note 9.

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, coal facilities, equipment for coal and 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: White Rock Wind Projects, Garden Plain wind project, Horizon Hill wind project and the Northern Goldfields Solar Project.

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, 2021, the Company has funded approximately US$46 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. 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.

I. Transmission Line Loss Rule Proceeding

The Company has been participating in a line loss rule proceeding before the AUC. The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to recalculate loss factors for 2006 to 2016. The AUC approved an invoice settlement process and all three planned settlements have been received. The first two invoices were settled by the first quarter of 2021 and the third invoice settled in the second quarter of 2021. The true-up invoices issued by the AESO in the fourth quarter of 2021 were settled by Dec. 31, 2021, with no further invoices expected.

II. Fortescue Metals Group Ltd. ("FMG") at South Hedland Power Station

On May 2, 2021, the Company entered into a conditional settlement with FMG. The settlement was concluded and the actions were formally dismissed in the Supreme Court of Western Australia on Dec. 7, 2021. The settlement amount has been recorded as revenue in the fourth quarter of 2021, while all other balances previously provided for have been reversed. The settlement has resulted in FMG continuing as a customer of the South Hedland facility.

III. Mangrove Claim

On April 23, 2019, the Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice naming the Company, the incumbent members of the Board of the Company on such date, and Brookfield as defendants. Mangrove was seeking to set aside the 2019 Brookfield transaction. The parties reached a confidential settlement and the action was discontinued in the Ontario Superior Court of Justice on April 30, 2021.

IV. Keephills 1 Stator Force Majeure

The Balancing Pool and ENMAX Energy Corporation ("ENMAX")are seeking to set aside an arbitration award on the basis that they did not receive a fair hearing. The Alberta Court of Queen's Bench ("ABQB") dismissed the Balancing Pool and ENMAX's allegations of unfairness on June 26, 2019. The Balancing Pool and ENMAX, however, sought leave to appeal the ABQB's decision at the Court of Appeal, which was granted on Feb. 13, 2020. The appeal was heard on July 8, 2021. After the hearing, counsel for ENMAX raised concerns that one of the three justices on the appeal panel was distracted during the hearing. The justice has since recused herself from the hearing and the parties made submissions with respect to whether the remaining two justices can continue to issue the decision or whether a new hearing is required. On Nov. 8, 2021, the Alberta Court of Appeal released its decision and ordered that the appeal be re-heard by a new three-person panel of the Court of Appeal, which was heard on Jan. 27, 2022. TransAlta remains of the view that the Court of Appeal will affirm the ABQB decision that the arbitration proceeding was fair.

V. Keephills 1 Superheater Force Majeure

Keephills Unit 1 was taken offline from March 17, 2015, to May 17, 2015, as a result of a large leak in the secondary superheater. TransAlta claimed force majeure under the Alberta PPA. ENMAX, the purchaser under the Alberta PPA at the time, did not dispute the force majeure but the Balancing Pool attempted to do so, seeking to recover $12 million in capacity payment charges it paid to TransAlta while the unit was offline. The parties reached a confidential settlement on April 21, 2021, and this matter is now resolved.

VI. Sundance A Decommissioning

TransAlta filed an application with the AUC seeking payment from the Balancing Pool for TransAlta's decommissioning costs for Sundance A, including its proportionate share of the Highvale mine. The Balancing Pool and Utilities Consumer Advocate are participating as interveners because they take issue with the decommissioning costs claimed by TransAlta. Due to various factors, including the COVID-19 pandemic and significant information requests from the Balancing Pool, the application has been delayed. While a hearing date has not been set, the application will likely be heard in late 2022 or early 2023. TransAlta expects to receive payment from the Balancing Pool for its decommissioning costs; however, the amount that the AUC will award is uncertain.

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

The Balancing Pool claims to be entitled to emission performance credits ("EPCs") earned by the Hydro facilities as a result of opting those facilities into the *Carbon Competitiveness Incentive Regulation* from 2018-2020 inclusive. The Balancing Pool claims ownership of the EPCs because it believes the change-in-law provisions under the Hydro PPA require the EPCs to be passed through to the Balancing Pool. TransAlta has not received any benefit from the EPCs or 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 is scheduled for Feb. 6-10, 2023.

VIII. Direct Assigned Capital Deferral Account ("DACDA") Application

AltaLink Management Ltd. ("AltaLink") and TransAlta (as a secondary applicant) filed an application before the AUC to recover its 2016-2018 DACDA costs incurred for the 240 kV line upgrades for the Edmonton Region Project. The AUC disallowed 15 per cent (approximately $3 million) of TransAlta's portion. TransAlta disputed this finding and filed a permission to appeal application with the Court of Appeal and a review and variance application with the AUC (the "R&V"). The AUC dismissed the R&V application on April 22, 2021. The permission to appeal was subsequently discontinued on July 5, 2021, which concludes this matter.

IX. Sarnia Outages

The Sarnia cogeneration facility experienced three separate outages between May 19, 2021, and June 9, 2021, that resulted in steam interruptions to its industrial customers. As a result, the customers have submitted claims for liquidated damages. Steam supply disruptions of this nature are atypical and infrequent at the Sarnia cogeneration facility. The Company conducted an investigation to determine the root cause of each of the three events, which concluded all three outages were within TransAlta's control. As such, liquidated damages in an amount dictated by the applicable agreements are payable by TransAlta to the customers for the three outages.

X. Kaybob 3 Cogeneration Dispute

The Company is engaged in a dispute with ET Canada as a result of ET Canada's purported termination of agreements between the parties to develop, construct and operate a 40 MW cogeneration facility at the Kaybob South No. 3 sour gas processing facility. TransAlta commenced an arbitration seeking full compensation for ET Canada's wrongful termination of the agreements. ET Canada seeks a declaration that the agreements were lawfully terminated. A hearing is scheduled for two weeks starting Jan. 9, 2023.

37. 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 CODM reviews 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 and 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, 2021	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	Energy Marketing	Corporate	Total	Equity 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	–
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	1,132	728	173	4	2,768	(18)	(29)	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[4]	–	–	118	60	–	–	178	–	–	178
Gross margin	367	331	640	236	173	–	1,747	(18)	(240)	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 expense (income)	–	–	(40)	48	–	–	8	–	–	8
Reclassifications and adjustments:										
Royalty onerous contract and contract termination penalties	–	–	–	(48)	–	–	(48)	–	48	–
Adjusted net other operating income	–	–	(40)	–	–	–	(40)	–	48	8
Adjusted EBITDA	322	262	494	133	137	(85)	1,263			
Equity income from associate										9
Finance lease income										25
Depreciation and amortization										(529)
Asset impairment										(648)
Net interest expense[6]										(245)
Foreign exchange gain										16
Gain on sale of assets and other										54
Loss before income taxes										**(380)**

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(6) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

Year ended Dec. 31, 2020	Hydro	Wind & Solar[1]	Gas[2]	Energy Transition[3]	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)	—
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	143	7	2,174	(3)	(70)	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[4]	—	—	120	48	—	(5)	163	—	—	163
Gross margin	144	309	507	290	143	—	1,393	(3)	(257)	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 expense (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[5]	105	248	367	175	113	(81)	927			
Equity income from associate										1
Finance lease income										7
Depreciation and amortization										(654)
Asset impairment										(84)
Net interest expense[6]										(238)
Foreign exchange loss										17
Gain on sale of assets and other										9
Loss before income taxes										(303)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(3) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(4) As of the first quarter of 2021, carbon compliance costs have been reclassified from fuel and purchase power costs and disclosed separately. Prior periods have been adjusted for comparative purposes.
(5) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(6) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

Year ended Dec. 31, 2019	Hydro	Wind & Solar	Gas[(1)]	Energy Transition[(2)]	Energy Marketing	Corporate	Total	Reclass adjustments	IFRS financials
Revenues	156	312	851	905	129	(6)	2,347	—	2,347
Reclassifications and adjustments:									
Unrealized mark-to-market (gain) loss	—	(17)	6	(12)	(10)	—	(33)	33	—
Decrease in finance lease receivable	—	—	24	—	—	—	24	(24)	—
Finance lease income	—	—	6	—	—	—	6	(6)	—
Adjusted revenues	156	295	887	893	119	(6)	2,344	3	2,347
Fuel and purchased power	7	16	315	539	—	4	881	—	881
Reclassifications and adjustments:									
Australian interest income	—	—	(4)	—	—	—	(4)	4	—
Mine depreciation	—	—	(81)	(40)	—	—	(121)	121	—
Adjusted fuel and purchased power	7	16	230	499	—	4	756	125	881
Carbon compliance	—	—	138	77	—	(10)	205	—	205
Gross margin	149	279	519	317	119	—	1,383	(122)	1,261
OM&A	36	50	162	124	30	73	475	—	475
Taxes, other than income taxes	3	8	9	8	—	1	29	—	29
Net other operating expense (income)	—	(10)	(41)	—	—	2	(49)	—	(49)
Termination of Sundance B and C PPAs	—	—	(14)	(42)	—	—	(56)	—	(56)
Adjusted EBITDA[(3)]	110	231	403	227	89	(76)	984		
Finance lease income									6
Depreciation and amortization									(590)
Asset impairment									(25)
Gain on termination of Keephills 3 coal rights contract									88
Net interest expense[(4)]									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.
(3) Adjusted EBITDA is not defined and has no standardized meaning under IFRS.
(4) Includes accretion by segment and interest expense is not allocated as its related to Corporate debt and borrowings.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2021	**Hydro**	**Wind and Solar**	**Gas[1]**	**Energy Transition[2]**	**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**

As at Dec. 31, 2020	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate	Total
PP&E	467	2,005	2,102	1,232	—	16	5,822
Right-of-use assets	6	55	5	53	—	22	141
Intangible assets	4	159	66	36	7	41	313
Goodwill	258	175	—	—	30	—	463

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2021	**Hydro**	**Wind and Solar**	**Gas[1]**	**Energy Transition[2]**	**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[1]	Energy Transition[2]	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	22	174	199	78	—	13	486
Intangible assets	—	—	—	1	—	13	14

Year ended Dec. 31, 2019	Hydro	Wind and Solar	Gas[1]	Energy Transition[2]	Energy Marketing	Corporate	Total
Additions to non-current assets:							
PP&E	23	229	74	90	—	1	417
Intangible assets	—	—	—	2	—	12	14

(1) Includes the segments previously known as Australian Gas and North American Gas and the gas generation assets from the segment previously known as Alberta Thermal.
(2) Includes the segment previously known as Centralia and the coal generation assets from the segment previously known as Alberta Thermal.

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	2021	2020	2019
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**529**	654	590
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**190**	144	119
Depreciation and amortization on the Consolidated Statements of Cash Flows	**719**	798	709

C. Geographic Information

I. Revenues

Year ended Dec. 31	2021	2020	2019
Canada	**1,854**	1,227	1,460
US	**731**	716	727
Australia	**136**	158	160
Total revenue	**2,721**	2,101	2,347

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets	
As at Dec. 31	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Canada	**4,051**	4,661	**52**	107	**141**	185	**15**	74
US	**860**	737	**39**	30	**85**	94	**61**	61
Australia	**409**	424	**4**	4	**30**	34	**66**	71
Total	**5,320**	5,822	**95**	141	**256**	313	**142**	206

D. Significant Customer

During the year ended Dec. 31, 2021, sales to the AESO represent 35 per cent of the Company's total revenue (2020 – sales to the AESO represented 15 per cent of the Company's total revenue). There were no other companies greater than 10 per cent of the Company's total revenue.