TransAlta Corporation

Consolidated Financial Statements

December 31, 2020

Consolidated Financial Statements

Management's Report

To the Shareholders of TransAlta Corporation

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

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

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

Dawn L. Farrell
President and Chief Executive Officer

Todd Stack
Executive Vice President, Finance and
Chief Financial Officer

March 2, 2021

Management's Annual Report on Internal Control Over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

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

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

TransAlta proportionately consolidates the joint operations of the Sheerness Generating Station, and Pioneer Pipeline Limited Partnership and we equity account for our investments in SP Skookumchuck Investment, LLC and EMG International, LLC in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements and associates. Once the financial information is obtained from these joint arrangements and associates it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements and associates.

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

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at Dec. 31, 2020, and has concluded that such internal control over financial reporting is effective.

Ernst & Young LLP, who has audited the consolidated financial statements of TransAlta for the year ended Dec. 31, 2020, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

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

March 2, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on Internal Control Over Financial Reporting

We have audited TransAlta Corporation's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the "COSO criteria"). In our opinion, TransAlta Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on the COSO criteria.

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the joint operations and equity accounted investments of the Sheerness Generating Station, Pioneer Pipeline Limited Partnership, SP Skookumchuk Investment, LLC and EMG International, LLC, which are included in the 2020 consolidated financial statements of TransAlta Corporation and constituted $481 million and $394 million of total and net assets, respectively, as of December 31, 2020, and $112 million and $6 million of revenues and net earnings (loss), respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation also did not include an evaluation of the internal control over financial reporting of the joint operations and equity accounted investments of the Sheerness Generating Station, Pioneer Pipeline Limited Partnership, SP Skookumchuck Investment, LLC and EMG International, LLC.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated statements of financial position of TransAlta Corporation as of December 31, 2020 and 2019, and the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2020, and the related notes and our report dated March 2, 2021 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
March 2, 2021

Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of TransAlta Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of TransAlta Corporation (the "Corporation") as of December 31, 2020 and 2019, the related consolidated statements of earnings (loss), comprehensive income (loss), changes in equity and cash flows, for each of the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of TransAlta Corporation at December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 2, 2021 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

Critical Audit Matters

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

Long-Lived Assets within the Centralia Thermal Plant cash generating unit ("CGU") & Goodwill related to the Wind and Solar segment

Description of the Matter

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

We identified the assessment of indicators of impairment for the Centralia Thermal Plant CGU as a critical audit matter because it involves auditing the judgment applied by management to assess various external and internal sources of information, more specifically if significant changes with an adverse effect on the Corporation have taken place during the year, or will take place in the near future, in the market or economic environment. Determining the recoverable amount for the Wind and Solar segment for the purposes of the annual goodwill impairment test was identified as a critical audit matter due to the significant estimation uncertainty and judgement applied by management in determining the recoverable amount, primarily due to the sensitivity of the significant assumptions to the future cash flows and the effect that changes in these assumptions would have on the recoverable amount. The estimates with a high degree of subjectivity include forecasted future cash flows, generation profiles, and commodity prices, and determining the appropriate discount rate.

How We Addressed the Matter in Our Audit

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

Valuation of Level III Derivative Instruments

Description of the Matter

As disclosed in notes 2(Z)(V) and 15 of the consolidated financial statements, the Corporation enters into transactions that are accounted for as derivative financial instruments and are recorded at fair value. The valuation of derivative instruments classified as level III are determined using assumptions that are not readily observable. As at December 31, 2020 the Corporation's derivative financial instruments classified as level III were $582 million.

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

How We Addressed the Matter in Our Audit

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

Ernst & Young LLP

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

Consolidated Statements of Earnings (Loss)

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

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

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

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

See accompanying notes.

Consolidated Statements of Financial Position

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

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

On behalf of the Board:

John P. Dielwart
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2018	$3,059	$942	$11	$ (1,496)	$481	$2,997	$1,137	$4,134
Adjustments on implementation of IFRS 16	—	—	—	3	—	3	—	3
Adjusted balance as at Jan. 1, 2019	3,059	942	11	(1,493)	481	3,000	1,137	4,137
Net earnings	—	—	—	82	—	82	94	176
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(38)	(38)	—	(38)
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	19	19	—	19
Net actuarial losses on defined benefits plans, net of tax	—	—	—	—	(26)	(26)	—	(26)
Intercompany FVOCI investments	—	—	—	—	17	17	(17)	—
Total comprehensive income (loss)				82	(28)	54	77	131
Common share dividends	—	—	—	(34)	—	(34)	—	(34)
Preferred share dividends	—	—	—	(30)	—	(30)	—	(30)
Shares purchased under NCIB	(83)	—	—	15	—	(68)	—	(68)
Changes in non-controlling interests in TransAlta Renewables (Note 4(V) and 13)	—	—	—	5	1	6	22	28
Effect of share-based payment plans	2	—	31	—	—	33	—	33
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(135)	(135)
Balance, Dec. 31, 2019	2,978	942	42	(1,455)	454	2,961	1,101	4,062
Net earnings (loss)	**—**	**—**	**—**	**(287)**	**—**	**(287)**	**34**	**(253)**
Other comprehensive income (loss):								
Net losses on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(91)**	**(91)**	**—**	**(91)**
Net actuarial losses on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**(11)**	**(11)**	**—**	**(11)**
Intercompany FVOCI investments	**—**	**—**	**—**	**—**	**(50)**	**(50)**	**50**	**—**
Total comprehensive income (loss)				**(287)**	**(152)**	**(439)**	**84**	**(355)**
Common share dividends	**—**	**—**	**—**	**(58)**	**—**	**(58)**	**—**	**(58)**
Preferred share dividends	**—**	**—**	**—**	**(49)**	**—**	**(49)**	**—**	**(49)**
Shares purchased under NCIB	**(79)**	**—**	**—**	**18**	**—**	**(61)**	**—**	**(61)**
Changes in non-controlling interests in TransAlta Renewables	**—**	**—**	**—**	**5**	**—**	**5**	**15**	**20**
Effect of share-based payment plans (Note 30)	**(3)**	**—**	**(4)**	**—**	**—**	**(7)**	**—**	**(7)**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(116)**	**(116)**
Balance, Dec. 31, 2020	**2,896**	**942**	**38**	**(1,826)**	**302**	**2,352**	**1,084**	**3,436**

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

Consolidated Statements of Cash Flows

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

See accompanying notes.

Notes to Consolidated Financial Statements

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

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

The six generation segments of the Corporation are as follows: Hydro, Wind and Solar, North American Gas, Australian Gas, Alberta Thermal, and Centralia. The Corporation directly or indirectly owns and operates hydro, wind and solar, natural gas-fired and coal-fired facilities, related mining operations and natural gas pipeline operations in Canada, the United States ("US") and Australia. The Wind and Solar segment includes the financial results, on a proportionate basis, of our investment in SP Skookumchuck Investment LLC. Revenues are derived from the availability and production of electricity and steam as well as ancillary services such as system support. Electricity sales made by the Corporation's commercial and industrial group are assumed to be sourced from the Corporation's production and have been included in the Alberta Thermal segment.

II. Energy Marketing Segment

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

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

III. Corporate and Other Segment

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

B. Basis of Preparation

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

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

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

C. Basis of Consolidation

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

2. Significant Accounting Policies

A. Revenue Recognition

I. Revenue from Contracts with Customers

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

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

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

When multiple performance obligations are present in a contract, transaction price is allocated to each performance obligation in an amount that depicts the consideration the Corporation expects to be entitled to in exchange for transferring the good or service. The Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their relative stand-alone selling prices, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

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

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

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

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

II. Revenue from Other Sources

Lease Revenue

In certain situations, a long-term electricity or thermal sales contract may contain, or be considered, a lease. Revenues associated with non-lease elements are recognized as goods or services revenues as outlined above. Where the terms and conditions of the contract result in the customer assuming the principal risks and rewards of ownership of the underlying asset, the contractual arrangement is considered a finance lease, which results in the recognition of finance lease income. Where the Corporation retains the principal risks and rewards, the contractual arrangement is an operating lease. Rental income, including contingent rents where applicable, is recognized over the term of the contract.

Revenue from Derivatives

Commodity risk management activities involve the use of derivatives such as physical and financial swaps, forward sales contracts, futures contracts and options, which are used to earn revenues and to gain market information. These derivatives are accounted for using fair value accounting. The initial recognition and subsequent changes in fair value affect reported net earnings in the period the change occurs and are presented on a net basis in revenue. The fair values of instruments that remain open at the end of the reporting period represent unrealized gains or losses and are presented on the Consolidated Statements of Financial Position as risk management assets or liabilities. Some of the derivatives used by the Corporation in trading activities are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available. The fair values of these derivatives are determined using internal valuation techniques or models.

B. Foreign Currency Translation

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

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

C. Financial Instruments and Hedges

I. Financial Instruments

Classification and Measurement

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

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

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

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

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

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

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

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

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

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

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

Impairment of Financial Assets

TransAlta recognizes an allowance for expected credit losses for financial assets measured at amortized cost as well as certain other instruments. The loss allowance for a financial asset is measured at an amount equal to the lifetime expected credit loss if its credit risk has increased significantly since initial recognition or if the financial asset is a purchased or originated credit-impaired financial asset. If the credit risk on a financial asset has not increased significantly since initial recognition, its loss allowance is measured at an amount equal to the 12-month expected credit loss.

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

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

II. Hedges

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

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

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

Fair Value Hedges

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

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

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

Cash Flow Hedges

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

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

Hedges of Foreign Currency Exposures of a Net Investment in a Foreign Operation

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

D. Cash and Cash Equivalents

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

E. Collateral Paid and Received

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

F. Inventory

I. Fuel

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

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

II. Energy Marketing

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

III. Parts, Materials and Supplies

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

IV. Emission Credits and Allowances

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

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

G. Property, Plant and Equipment

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

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

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

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

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

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

Hydro generation	1-52 years
Wind generation	1-29 years
Gas generation	1-17 years
Coal generation	1-29 years
Mining property and equipment	1-9 years
Capital spares and other	2-52 years

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

H. Intangible Assets

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

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

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

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

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

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

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

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

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

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

J. Goodwill

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

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

K. Project Development Costs

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

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

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

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

P. Assets Held for Sale

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

Q. Leases

I. Lease Policy for 2019 and 2020

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

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

Lessee

The Corporation enters into lease arrangements with respect to land, building and office space, vehicles and site machinery and equipment. For all contracts that meet the definition of a lease under IFRS 16 in which the Corporation is the lessee, and which are not exempt as short-term or low-value leases, the Corporation:

- Recognizes right-of-use assets and lease liabilities in the Consolidated Statements of Financial Position;
- Recognizes depreciation of the right-of-use assets and interest expense on lease liabilities in the Consolidated Statements of Earnings (Loss); and
- Recognizes the principal repayments on lease liabilities as financing activities and interest payments on lease liabilities as operating activities in the Consolidated Statements of Cash Flows.

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

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

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

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

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

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

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

Lessor

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

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

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

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

II. Lease Policy Prior to 2019

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

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

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

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

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

R. Borrowing Costs

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

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

S. Non-Controlling Interests

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

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

T. Joint Arrangements

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

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

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

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

U. Investments in Associates

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

Investments in associates are accounted for using the equity method of accounting. Under the equity method, the investment is initially recognized at cost and the carrying amount is increased or decreased to recognize the Corporation’s share of the associate’s net earnings or loss after the date of acquisition. The Corporation’s share of the associate’s net earnings or loss is recognized in net earnings. Distributions received from the associate reduce the carrying amount of the investment

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

V. Government Incentives

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

W. Earnings per Share

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

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

X. Business Combinations

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

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

Y. Stripping Costs

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

Z. Significant Accounting Judgments and Key Sources of Estimation Uncertainty

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

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

I. COVID-19

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

II. Impairment of PP&E and Goodwill

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

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

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

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

With regard to the allocation or reallocation of goodwill, significant judgment is required to evaluate synergies and their impacts. Minimum thresholds also exist with respect to segmentation and internal monitoring activities. The Corporation evaluates synergies with regards to opportunities from combined talent and technology, functional organization and future growth potential, and considers its own performance measurement processes in making this determination. Information regarding significant judgments and estimates in respect of impairment during 2018 to 2020 is found in Notes 7, 18 and 21.

III. Leases

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

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

IV. Income Taxes

Preparation of the consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Corporation operates. The process also involves making an estimate of income taxes currently payable and income taxes expected to be payable or recoverable in future periods, referred to as deferred income taxes. Deferred income taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the Consolidated Statements of Financial Position as deferred income tax assets and liabilities. An assessment must also be made to determine the likelihood that the Corporation's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, deferred income tax assets must be reduced. Management uses the Corporation's long-range forecasts as a basis for evaluation of recovery of deferred income tax assets. Management must exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation to ensure deferred income tax assets and liabilities are complete and fairly presented. Differing assessments and applications than the Corporation's estimates could materially impact the amounts recognized for deferred income tax assets and liabilities. See Note 12 for further details on the impacts of the Corporation's tax policies.

V. Financial Instruments and Derivatives

The Corporation's financial instruments and derivatives are accounted for at fair value, with the initial and subsequent changes in fair value affecting earnings in the period the change occurs. The fair values of financial instruments and derivatives are classified within three levels, with Level III fair values determined using inputs for the asset or liability that are not readily observable. These fair value levels are outlined and discussed in more detail in Note 15. Some of the Corporation's fair values are included in Level III because they are not traded on an active exchange or have terms that extend beyond the time period for which exchange-based quotes are available and require the use of internal valuation techniques or models to determine fair value.

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

When the Corporation enters into contracts to buy or sell non-financial items, such as certain commodities, and the contracts can be settled net in cash, the Corporation must use judgment to evaluate whether such contracts were entered into and continue to be held for the purposes of the receipt or delivery of the commodity in accordance with the Corporation's expected purchase, sale or usage requirements (i.e., normal purchase and sale). If this assertion cannot be supported, initially at contract inception and on an ongoing basis, the contracts must be accounted for as derivatives and measured at fair value, with changes in fair value recognized in net earnings. In supporting the normal purchase and sale assertion, the Corporation considers the nature of the contracts, the forecasted demand and supply requirements to which the contracts relate, and its past practice of net settling other similar contracts, which may taint the normal purchase and sale assertion.

VI. Project Development Costs

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

VII. Provisions for Decommissioning and Restoration Activities

TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 23. Initial decommissioning provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the required cash expenditures, adjusted to reflect the risks and uncertainties inherent in the timing and amount of settlement. The estimated cash expenditures are present valued using a current, risk-adjusted, market-based, pre-tax discount rate. A change in estimated cash flows, market interest rates or timing could have a material impact on the carrying amount of the provision. Information regarding significant judgments and estimates made during 2020 in respect of decommissioning and restoration provisions can be found in Note 3(A)(III) and Notes 7 and 23.

VIII. Useful Life of PP&E

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

IX. Employee Future Benefits

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

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

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

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

X. Other Provisions
Where necessary, the Corporation recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4, 9 and 23 with respect to other provisions.

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

In determining the transaction price and estimates of variable consideration, management considers the past history of customer usage in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets. The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their stand-alone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

The satisfaction of performance obligations requires management to make judgments as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs.

Management also applies judgment in determining whether the invoice practical expedient permits recognition of revenue at the invoiced amount, if that invoiced amount corresponds directly with the entity's performance to date.

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

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

3. Accounting Changes

A. Current Accounting Changes

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

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

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

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

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

III. Change in Estimates

Useful Life of PP&E at Alberta Thermal

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

During the third quarter of 2019, the Corporation adjusted the useful lives of certain coal assets, effective Sept. 1, 2019, to reflect the changes announced related to the Clean Energy Investment Plan (see Note 4(A) for further details). As a result, assets used only for coal-burning operations were adjusted to shorten their useful lives whereas other asset lives were extended as they were identified as being used after the coal-to-gas or combined-cycle conversions. Due to the impact of shortening the lives of the coal assets, overall depreciation expense for the year ended Dec. 31, 2019 increased by approximately $16 million.

In 2018, as a result of the Off-Coal Agreement (“OCA”) with the Government of Alberta described in Note 9(B), the Corporation adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. As a result, depreciation expense and intangibles amortization for the year ended Dec.31, 2018, increased by $38 million.

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

Useful Life of PP&E at Wind and Solar

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

Sheerness

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

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

Decommissioning and other provisions

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

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

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

B. Future Accounting Changes

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

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

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

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

C. Comparative Figures

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

4. Significant and Subsequent Events

A. Clean Energy Investment Plan

TransAlta's Clean Energy Investment Plan announced in 2019 includes converting our existing Alberta coal assets to natural gas and advancing our leadership position in on-site generation and renewable energy. The Clean Energy Investment Plan provided further details of previously highlighted initiatives that TransAlta has been continuing to progress since early 2017.

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

The highlights of these gas conversion investments include:

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

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

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

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

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

B. Pioneer Pipeline

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 per cent ownership in the Pioneer gas pipeline ("Pioneer Pipeline") for $83 million. Tidewater Midstream & Infrastructure Ltd.'s ("TMI") and TransAlta each own a 50 per cent interest in the Pioneer Pipeline, which is backstopped by a 15-year take-or-pay agreement from TransAlta at market rate tolls. During the fourth quarter of 2019, TransAlta recognized a right-of-use asset and lease liability for the portion of the Pioneer Pipeline that is not directly owned.

During 2019, the Pioneer Pipeline transported its first gas four months ahead of schedule to TransAlta's generating units at Sundance and Keephills. The Pioneer Pipeline initially had approximately 50 MMcf/day of natural gas flowing during the start-up phase where initial flows fluctuated depending on market conditions. Firm throughput of approximately 130 MMcf/day of natural gas began flowing through the Pioneer Pipeline on Nov. 1, 2019.

The Pioneer Pipeline is held in a separate entity that is a joint operation with TMI. The Corporation reports its interests in joint operations in its consolidated financial statements using the proportionate consolidation method by recognizing its share of the assets, liabilities, revenues and expenses in respect of its interest in the joint operation within the Alberta Thermal segment. The Pioneer Pipeline is classified as a joint operation, due to the fact that TransAlta is currently the only customer and both parties are providing the only cash flows to fund the operations.

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

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

C. Skookumchuck Wind Project

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

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

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

D. WindCharger

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

E. Windrise

On Dec. 17, 2018, TransAlta's 207 MW Windrise wind project was identified by the AESO as one of the three selected projects in the third round of the Renewable Electricity Program. TransAlta and the AESO subsequently executed a Renewable Electricity Support Agreement with a 20-year term. Windrise is situated on 11,000 acres of land located in the county of Willow Creek, Alberta, and is expected to cost approximately $270 million to $285 million. Windrise has secured approval for the wind facility and transmission line required to connect the facility to the Alberta grid from the AUC. Construction activities on Windrise continue to advance with all appropriate procedures in place to protect the construction team during the COVID-19 pandemic. However as a result of COVID-19 and related delays in construction, the commercial operation date is expected to occur during the second half of 2021. As of Dec. 31, 2020, Windrise was 78 per cent complete. On Feb. 26, 2021, TransAlta Renewables acquired Windrise from the Corporation as described further below.

F. Acquisition of Wind Development Projects

In 2019, TransAlta acquired a portfolio of wind development projects in the US. If the Corporation decides to move forward with any of these projects, additional consideration may be payable on a project-by-project basis only in the event a project achieves commercial operations prior to Dec. 31, 2025.

G. EMG International Acquisition

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

H. TransAlta Renewables Acquisitions

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

I. BHP Nickel West Contract Extension

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

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

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

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

On Oct. 1, 2019, TransAlta and Energy Transfer Canada ("ET Canada" formerly known as SemCAMS Midstream ULC) entered into definitive agreements to develop, construct and operate a 40 MW cogeneration facility at the Kaybob

South No. 3 sour gas processing plant. The facility was expected to receive its final regulatory approvals in the second half of the year and begin construction in December 2020. On Sept. 25, 2020, the AUC released a decision in which it approved the construction and operation of the facility, but denied the application for the Industrial System Designation. We are in ongoing commercial and technical discussions with ET Canada relative to the project at K3, or potentially developing a new project at another site owned and/or operated by ET Canada.

K. Acquisition of a Contracted Cogeneration Asset in Michigan

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

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

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

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

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

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

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

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

M. Strategic Investment by Brookfield

On March 22, 2019, the Corporation entered into an agreement (the "Investment Agreement") whereby Brookfield Renewable Partners or its affiliates (collectively “Brookfield”) agreed to invest $750 million (the "Investment") in the Corporation through the purchase of exchangeable securities. The securities are exchangeable by Brookfield into an equity ownership interest in TransAlta’s Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets’ future adjusted earnings before interest, taxes, depreciation and amortization ("EBITDA").

On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in consideration for redeemable, retractable first preferred shares. The proceeds from the first tranche were used to accelerate our conversion to gas program. The Corporation intends to use the proceeds from the second tranche of the financing to advance the Corporation's conversion to gas program, to fund other growth initiatives and for general corporate purposes.

Upon entering into the Investment Agreement and as required under the terms of the agreement, the Corporation paid Brookfield a $7.5 million structuring fee. A commitment fee of $15 million was also paid upon completion of the initial funding. These transaction costs, representing three per cent of the total investment of $750 million, have been recognized as part of the carrying value of the unsecured subordinated debentures. See Note 25 for further details.

In accordance with the terms of the Investment Agreement, TransAlta has formed a Hydro Assets Operating Committee consisting of two representatives from Brookfield and two representatives from TransAlta to collaborate in connection with the operation and maximization of the value of the Alberta Hydro Assets. In connection with this, the Corporation has committed to pay Brookfield an annual fee of $1.5 million for six years beginning May 1, 2019 (the "Brookfield Hydro Fee"), which is recognized in the operations, maintenance and administration expense on the Consolidated Statements of Earnings (Loss).

TransAlta has indicated that it intends to return up to $250 million of capital to shareholders through share repurchases within three years of receiving the first tranche of the Investment. As of Dec. 31, 2020, 15,068,900 common shares have been repurchased and $129 million under the normal course issuer bid normal course issuer bid("NCIB") program.

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

On April 23, 2019, the Mangrove Partners Master Fund Ltd. ("Mangrove") commenced an action in the Ontario Superior Court of Justice alleging, among other things, oppression by the Corporation and its directors and seeking to set aside the Brookfield Investment Agreement. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter was adjourned due to the COVID-19 pandemic and is now scheduled to proceed to trial for three weeks starting April 19, 2021. Refer to Note 36 for further details.

N. Centralia Unit 1 Retirement

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

O. Mothballing of Sundance Units and Sundance Unit 3 Retirement

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

P. COVID-19

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

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

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

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

Q. Normal Course Issuer Bid

2020

On May 26, 2020, the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to the NCIB, the Corporation may repurchase up to a maximum of 14,000,000 common Shares, representing approximately 7.02 per cent of its public float of common shares as at May 25, 2020. Purchases under the NCIB may be made through open market transactions on the TSX and any alternative Canadian trading platforms on which the common shares are traded, based on the prevailing market price. Any common shares purchased under the NCIB will be cancelled.

The period during which the Corporation is authorized to make purchases under the NCIB commenced on May 29, 2020, and ends on May 28, 2021, or such earlier date on which the maximum number of common shares are purchased under the NCIB or the NCIB is terminated at the Corporation’s election.

Under TSX rules, not more than 228,157 common shares (being 25 per cent of the average daily trading volume on the TSX of 912,630 common shares for the six months ended April 30, 2020) can be purchased on the TSX on any single trading day under the NCIB, with the exception that one block purchase in excess of the daily maximum is permitted per calendar week.

During the year ended Dec. 31, 2020, under the current and previous NCIB, the Corporation purchased and cancelled a total of 7,352,600 common shares at an average price of $8.33 per common share, for a total cost of $61 million. See Note 27 for further details.

2019

On May 27, 2019, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement a NCIB for a portion of its common shares. Pursuant to such NCIB, the Corporation was permitted to repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.92 per cent of issued and outstanding common shares as at May 27, 2019.

During the year ended Dec. 31, 2019, the Corporation purchased and cancelled a total of 7,716,300 common shares at an average price of $8.80 per common share, for a total cost of $68 million. See Note 27 for further details.

2018

On March 9, 2018, the Corporation announced that the TSX accepted the notice filed by the Corporation to implement an NCIB for a portion of its common shares. Pursuant to such NCIB, the Corporation was permitted to repurchase up to a maximum of 14,000,000 common shares, representing approximately 4.86 per cent of issued and outstanding common shares as at March 2, 2018.

During the year ended Dec. 31, 2018, the Corporation purchased and cancelled a total of 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million.

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

On Oct. 1, 2019, the Corporation closed a transaction with Capital Power Corporation ("Capital Power") to swap TransAlta's 50 per cent ownership interest in the 466 MW Genesee 3 facility for Capital Power's 50 per cent ownership interest in the 463 MW Keephills 3 facility. As a result, TransAlta now owns 100 per cent of the Keephills 3 facility and Capital Power owns 100 per cent of the Genesee 3 facility.

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

In 2019, the Corporation early-adopted 2020 amendments to IFRS 3 *Business Combinations*, which introduce an optional fair value concentration test. The Corporation elected to apply the optional fair value concentration test to its acquisition of the non-operating interest in Keephills 3, through which it was determined that greater than 90 per cent of the fair value was concentrated in the PP&E acquired. As a result, the acquisition was determined to not be a business and IFRS 3 requirements were not applied and the existing carrying amount of the owned 50 per cent of Keephills 3 was not required to be assessed at fair value. Consequently, the acquisition has been accounted for as an asset acquisition, with the following carrying amounts assigned based on relative fair values:

Working capital	11
Property, plant and equipment	308
Other assets	3
Other liabilities	(2)
Decommissioning and other provisions	(19)
Total acquisition cost	**301**

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

On the closing of the transaction, all of the Keephills 3 and Genesee 3 project agreements with Capital Power were terminated, including the agreement governing the supply of coal from TransAlta's Highvale mine to the Keephills 3 facility. The Highvale mine accounted for the revenues generated under this agreement pursuant to IFRS 15 *Revenue from Contracts with Customers*, which resulted in the recognition of a contract liability representing the mine's unsatisfied performance obligations for which consideration was received in advance. On Oct. 1, 2019, upon termination of this agreement, the Highvale mine had no future performance obligations and accordingly, the balance of the contract liability of $88 million was recognized in earnings in the fourth quarter of 2019.

S. Termination of the Alberta Sundance Power Purchase Arrangement

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

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

T. US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it entered into an arrangement to acquire interests in two construction-ready wind projects in the Northeastern United States (collectively, the "US Wind Projects"). Big Level consists of a 90 MW wind project located in Pennsylvania that has a 15-year PPA with Microsoft Corporation, and Antrim consists of a 29 MW wind project located in New Hampshire with two 20-year PPAs with Partners Healthcare and New Hampshire Electric Co-op. The Counterparties in the PPAs all have a Standard & Poor's credit ratings of A+ or better.

A subsidiary of TransAlta acquired Big Level on March 1, 2018, and Antrim on March 28, 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in Big Level from a subsidiary of TransAlta Power Ltd. ("TA Power"). Pursuant to the arrangement, a TransAlta subsidiary owns Big Level directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of Big Level. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power.

On March 28, 2019, the closing conditions related to the acquisition of Antrim were finalized and the TransAlta subsidiary acquired the development project for total cash consideration of $24 million and the settlement of the balance of the outstanding loan receivable of $41 million. As a result, the Corporation recognized $50 million for assets under construction in PP&E and $15 million in intangibles. The TransAlta subsidiary also paid the final holdback for the Big Level development project of $7 million (US$5 million) on the closing of Antrim.

During 2019, TransAlta Renewables funded the acquisition of Antrim and the construction costs of the US Wind Projects by subscribing for $142 million (US$105 million) of interest-bearing promissory notes and $78 million (US$59 million) of tracking preferred shares.

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

Big Level and Antrim each began commercial operations in December 2019. In conjunction with reaching commercial operation, tax equity proceeds were raised to partially fund the US Wind Projects in the amount of approximately US$85 million for Big Level and approximately US$41 million for Antrim. The tax equity financing is classified as long-term debt on the Consolidated Statements of Financial Position.

From the tax equity proceeds, a subsidiary of TransAlta repaid $98 million (US$72 million) of the interest-bearing promissory notes from TransAlta Renewables. The remaining amount of the tax equity proceeds is held as reserves within the project entity and will be released upon certain conditions being met. Once these conditions are met, the reserves will be released and the subsidiary of TransAlta will repay the remaining outstanding interest-bearing promissory notes from TransAlta Renewables.

U. Kent Hills 3 Wind Project

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

V. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

The acquisition of Kent Breeze was accounted for by TransAlta Renewables as a business combination under common control, requiring the application of the pooling of interests method of accounting, whereby the assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at May 31, 2018, and not at their fair values. As a result, the Corporation recognized a transfer of equity from the non-controlling interests in the amount of $1 million in 2018.

On June 28, 2018, TransAlta Renewables subscribed for an additional $33 million (US$25 million) of tracking preferred shares of a subsidiary of the Corporation related to Mass Solar to fund the repayment of Mass Solar's project debt.

In connection with these acquisitions, the Corporation recorded a $12 million impairment charge, of which $11 million was recorded against PP&E and $1 million against intangibles. See Note 7 for further details.

W. TransAlta Renewables Closes $150- Million Share Offering of Common Shares

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

The net proceeds of the Share Offering were used to partially repay drawn amounts under TransAlta Renewables' credit facility, which was drawn in order to fund recent acquisitions. The additional liquidity under the credit facility was used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(J) above.

The Corporation did not purchase any additional common shares under the Share Offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 13 for further details of TransAlta's ownership of TransAlta Renewables.

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

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

The net proceeds were used to partially repay the 6.40 per cent debentures, as described in Note 24.

5. Revenue

A. Disaggregation of Revenue

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

Year ended Dec. 31, 2020	Hydro	Wind and Solar	North American Gas(1)	Australian Gas	Alberta Thermal(2)	Centralia(2)	Energy Marketing	Corporate and Other	Total
Revenues from contracts with customers	141	261	196	90	325	10	—	—	1,023
Revenue from leases(3)	—	—	8	60	55	—	—	—	123
Revenue from derivatives and other trading activities	—	(2)	4	—	(12)	283	122	12	407
Government incentives	1	4	—	—	—	—	—	—	5
Revenue from other(4)	10	66	9	8	251	204	—	(5)	543
Total revenue	152	329	217	158	619	497	122	7	2,101
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	—	25	—	—	23	10	—	—	58
Over time	141	236	196	90	302	—	—	—	965
Total revenue from contracts with customers	141	261	196	90	325	10	—	—	1,023

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

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

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

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

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

B. Contract Liabilities

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

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

(1) In 2019, on transition to IFRS 16, some contracts that were previously considered leases under IAS 17 did not meet the definition of a lease under IFRS 16 and therefore were assessed under IFRS 15 and balances were transferred from deferred revenue to contract liabilities.

The opening contract liabilities in 2019 were primarily comprised of consideration received from the Corporation's Keephills 3 joint operation partner, Capital Power, for which the Corporation had a future obligation to transfer goods and services to Capital Power under the contract. On closing of the Keephills 3 and Genesee 3 swap, wherein the Corporation acquired Capital Power's 50 per cent ownership interest in Keephills 3 and sold its 50 per cent ownership interest in Genesee 3, the agreement with Capital Power was terminated in 2019 and the Corporation no longer had any further performance obligations and the related contract liability balance was recognized in net earnings.

The remaining contract liabilities outstanding at Dec. 31, 2020, and Dec. 31, 2019, primarily relate to prepayments relating to the Corporation's New Richmond and Bone Creek facilities where the Corporation still has to fulfil its performance obligations.

C. Remaining Performance Obligations

The following disclosures regarding the aggregate amounts of transaction prices allocated to remaining performance obligations (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

Additionally, in many of the Corporation's contracts, elements of the transaction price are considered constrained, such as for variable revenues dependent upon future production volumes that are driven by customer or market demand or market prices that are subject to factors outside the Corporation's influence. Future revenues that are related to constrained variable consideration are not included in the disclosure of remaining performance obligations until the constraints are resolved. Further, adjustments to revenue to recognize a significant financing component in a contract are not included in the amounts disclosed for remaining performance obligations.

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

Hydro

At Dec. 31, 2020, the Corporation's PPA with the Balancing Pool to provide the capacity of 12 hydro facilities throughout the province of Alberta concluded. Future production will be sold into the merchant market. The Corporation has contracts for blackstart services at specific hydro facilities, which will conclude at the end of 2030. The Corporation also has a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which concludes in 2021.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2020, are approximately $31 million, which the Corporation expects to recognize approximately $8 million in 2021 and approximately $2 million to $3 million annually from 2022-2030.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to all hydro energy contracts in Ontario, British Columbia and Washington; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Wind and Solar

At Dec. 31, 2020, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from three wind facilities located in Alberta, Minnesota and Quebec, for which the invoice practical expedient is not applied. The PPAs generally require all available generation to be provided to customers at fixed prices, with certain pricing subject to annual escalations for inflation. The Corporation expects to recognize such amounts as revenue as it delivers electricity over the remaining terms of the contracts, until 2024, 2034 and 2033, respectively. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized over time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchasers over the remaining terms of the contracts, from 2020 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2020, are approximately $13 million, of which the Corporation expects to recognize between approximately $2 million to $5 million annually through to contract expiry.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to wind energy contracts in Ontario, New Brunswick, Quebec and Wyoming, and for all solar contracts; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

North American Gas

At Dec. 31, 2020, the Corporation has contracts with customers to deliver energy services from one of its gas facilities in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. A summary of the key terms of these contracts is set out below.

The energy supply agreements require specified amounts of steam to be delivered to each customer, and have pricing terms that include fixed and variable charges for electricity, capacity and steam, as well as a true-up based on contractual minimum volumes of steam. The steam reconciliation is based on an estimate of the customer's steam volume taken and the contractual minimum volume, and various factors including the annual average market price of electricity and the average locally posted and index prices of natural gas, as well as transportation. For steam volumes not taken by the customer, a revenue-sharing mechanism provides for sharing of revenues earned by the Corporation using that steam to generate and sell electricity. Capacity and electricity pricing vary from contract to contract and are subject to annual indexation at varying rates. Electricity and steam delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. The variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

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

At Dec. 31, 2020, the Corporation had contracts with customers to deliver steam, hot water and chilled water from one of its other gas facilities in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

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

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2020, are approximately $13 million in total, of which the Corporation expects to recognize between approximately $4 million to $5 million annually for the duration of the contracts.

The practical expedient allowing the recognition of revenue from the contract in an amount that is equal to the amount invoiced is applied to some of the Corporation's other gas facilities' contracts in Ontario and the United States; accordingly, disclosures related to remaining performance obligations are not provided for these contracts.

Australian Gas

At Dec. 31, 2020, the Corporation has PPAs with customers to deliver electricity from its gas facilities located in Australia. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2026 to 2042.

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

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

Alberta Thermal

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

The Corporation also has several contracts for sale of byproducts of coal combustion from certain of its coal facilities. The contracts range in duration from one to three years. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

The Corporation has a contract, commencing in late 2023, for the sale of capacity and electricity, exercisable at the option of the customer, under which the Corporation will receive a fixed capacity payment and variable energy payments based on production. Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2020, are approximately $336 million, of which the Corporation expects to recognize on average, between $5 million to $10 million in 2023 and $40 million to $45 million annually thereafter for the duration of the contracts.

Centralia

The Corporation's long-term contract for the sale of electricity produced at its US Coal plant is considered a derivative and is designated as an all-in-one hedge. Accordingly, while revenues for electricity delivered to the customer are recognized pursuant to the contractual terms, the revenues are not accounted for under IFRS 15 and the contract has been excluded from any required IFRS 15 disclosures.

The Corporation also has a contract for the sale of byproducts of coal combustion from its US Coal plant. Generally, revenues vary based on market prices that are subject to factors outside of the Corporation's control, and the quantities delivered and sold, which are ultimately dependent upon customer demand. These variable revenues are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of byproducts, is satisfied. Accordingly, these revenues are excluded from these disclosures.

6. Expenses by Nature

Expenses classified by nature are as follows:

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

7. Asset Impairment and Reversals

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

A. 2020

Sundance Unit 3

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

BC Hydro Facility

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

Centralia Land

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

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

B. 2019

Centralia Thermal Facility

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

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

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

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

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

Refer to Note 3(A)(III) and 23 for further details on the Centralia mine decommissioning and restoration provision.

Assets Held for Sale

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

C. 2018

Sundance Unit 2

In the third quarter of 2018, the Corporation recognized an impairment charge on Sundance Unit 2 in the amount of $38 million, due to the Corporation's decision to retire Sundance Unit 2. Previously, the Corporation had expected Sundance Unit 2 to remain mothballed for a period of up to two years and therefore remain within the Alberta merchant CGU. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the unit until its retirement on July 31, 2018. Discounting did not have a material impact.

Lakeswind and Kent Breeze

On May 31, 2018, TransAlta Renewables acquired an economic interest in Lakeswind through the subscription of tracking preferred shares of a subsidiary of the Corporation and also purchased Kent Breeze (see Note 4(V)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately seven per cent. Accordingly, the Corporation has recorded an impairment of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (refer to Note 18 and 20).

D. Project Development Costs

During 2020, the Corporation wrote off nil (2019 — $18 million; 2018 — $23 million) in project development costs related to projects that are no longer proceeding.

8. Finance Lease Receivables

Amounts receivable under the Corporation's finance leases associated with the Poplar Creek cogeneration facility and in 2020, the Southern Cross Energy facilities are as follows:

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

Included in the Consolidated Statements of Financial Position as:	2020	2019
Current portion of finance lease receivables (Note 14)	**36**	15
Long-term portion of finance lease receivables	**228**	176
	264	191

9. Net Other Operating Income

Net other operating income includes the following:

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

A.Onerous Contract Provision for Coal Supply Agreement

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

B. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030. The swap of ownership interests in Keephills 3 and Genesee 3 did not impact the payments received. Refer to Note 4(R) for further details.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), which commenced Jan. 1, 2017, and will terminate at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2030. In July 2018, the Corporation obtained financing against the OCA payments. Refer to Note 4(X) and 24 for further details.

C. Insurance Recoveries

There were no insurance recoveries in 2020.

During 2019, the Corporation received $10 million in insurance recoveries, which related to insurance proceeds for tower fires at Wyoming and Summerview.

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related to insurance proceeds for the tower fire at Wyoming and a $1 million claim related to equipment repairs within Alberta Thermal.

10. Investments

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

The change in investments is as follows:

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

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

Summarized financial information on the results of operations relating to the Corporation's pro-rata interests in Skookumchuck and EMG is as follows:

Year ended Dec. 31	2020
Results of operations	
Revenues	3
Expenses	(2)
Proportionate share of net earnings	1

On Nov. 25, 2020, TransAlta purchased a 49 per cent interest in Skookumchuck, a 136.8 MW wind facility located in Lewis and Thurston counties near Centralia in Washington state consisting of 38 Vestas 136 wind turbines. Summarized financial information relating to 100 per cent of Skookumchuck, including adjustments for the application of consistent accounting policies and the Corporation's purchase price adjustments, is as follows:

Year ended Dec. 31	2020
Revenues	6
Depreciation and amortization	2
Interest expense	1
Net earnings	3
Other comprehensive loss	—
Total comprehensive loss	3

As at Dec. 31	2020
Current assets	6
Non-current assets	382
Current liabilities	(65)
Non-current liabilities	(150)
Net assets	173
Additional items included above	
Cash and cash equivalents	1
Current financial liabilities(1)	(27)
Non-current financial liabilities(1)	(147)

(1) Excludes trade and other payables and provisions.

A reconciliation of the carrying amount to the Corporation's 49 per cent interest in the Skookumchuck is as follows:

As at Dec. 31	2020
Net assets	173
Less: 51 per cent of Skookumchuck net assets not owned by the Corporation	(88)
Net investment	85

Skookumchuck's ability to make distributions to its owners, including the Corporation, is dependent on available cash flow and is restricted by covenants and conditions, including principal and interest funding requirements imposed by the tax equity financing agreements.

Skookumchuck's approximate future payments under contractual commitments are as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Long-term service agreements(1)	1	1	1	1	1	28	33

(1) Refer to Note 36 for further details on long-term service agreements.

11. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2020	2019	2018
Interest on debt	**158**	161	184
Interest on exchangeable securities (Note 25)	**34**	20	—
Interest income	**(10)**	(13)	(11)
Capitalized interest (Note 18)	**(8)**	(6)	(2)
Loss on redemption of bonds (Note 24)	**—**	—	24
Interest on lease liabilities	**8**	4	3
Credit facility fees, bank charges and other interest	**18**	15	13
Tax shield on tax equity financing (Note 24)(1)	**1**	(35)	—
Interest on line loss rule proceeding (Note 36(I)(I))	**5**	—	—
Other(2)	**2**	10	15
Accretion of provisions (Note 23)	**30**	23	24
Net interest expense	**238**	179	250

(1) Relates to the tax benefit associated with bonus tax depreciation claimed in 2019 on the Big Level and Antrim projects that was assigned to the tax equity investor. The tax equity investment is treated as debt under IFRS and the monetization of the tax depreciation is considered a non-cash reduction of the debt balance and is reflected as a reduction in interest expense.

(2) In 2020, other interest expense included approximately nil (2019 — $5 million, 2018 — $7 million) for the significant financing component required under IFRS 15. In addition, in 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable.

12. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2020	2019	2018
Earnings (loss) before income taxes	**(303)**	193	(96)
Net earnings (loss) attributable to non-controlling interests not subject to tax	**2**	(26)	(19)
Adjusted earnings (loss) before income taxes	**(301)**	167	(115)
Statutory Canadian federal and provincial income tax rate (%)	**24.5%**	26.5%	26.8%
Expected income tax expense (recovery)	**(74)**	44	(31)
Increase (decrease) in income taxes resulting from:			
Differences in effective foreign tax rates	**3**	5	(3)
Deferred income tax expense related to temporary difference on investment in subsidiaries	**9**	—	—
Writedown (reversal of writedown) of deferred income tax assets	**8**	(9)	27
Statutory and other rate differences	**(7)**	(31)	—
Other	**11**	8	1
Income tax expense (recovery)	**(50)**	17	(6)
Effective tax rate (%)	**17%**	10%	5%

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2020	2019	2018
Current income tax expense	**35**	35	28
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(95)**	22	(61)
Deferred income tax expense related to temporary difference on investment in subsidiary	**9**	—	—
Deferred income tax recovery resulting from changes in tax rates or laws[(1)]	**(7)**	(31)	—
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[(2)]	**8**	(9)	27
Income tax expense (recovery)	**(50)**	17	(6)

Year ended Dec. 31	2020	2019	2018
Current income tax expense	**35**	35	28
Deferred income tax recovery	**(85)**	(18)	(34)
Income tax expense (recovery)	**(50)**	17	(6)

(1) In 2020 the Corporation recognized a deferred income tax recovery of $7 million (2019 —$31 million) related to a decrease in the Alberta corporate tax rate from 11 per cent to 8 per cent. The tax decrease was originally scheduled as follows: 11 per cent effective July 1, 2019, 10 per cent effective Jan. 1, 2020, 9 per cent effective Jan. 1, 2021, and 8 per cent effective Jan. 1, 2022. The Government of Alberta enacted the rate to decrease to 8 per cent effective Dec. 9, 2020.

(2) During the year ended Dec. 31, 2020, the Corporation recorded a writedown of deferred tax assets of $8 million (2019 — $9 million writedown reversal, 2018 — $27 million writedown). In the current year additional deferred tax assets were created from the recognition of other comprehensive losses in the US. The deferred income tax assets mainly relate to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation evaluates at each period end, whether it is probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses.

B. Consolidated Statements of Changes in Equity

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

Year ended Dec. 31	2020	2019	2018
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(23)**	6	(12)
Net actuarial gains (losses)	**(3)**	(7)	5
Income tax expense reported in equity	**(26)**	(1)	(7)

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2020	2019
Net operating loss carryforwards(1)	**469**	494
Future decommissioning and restoration costs	**140**	122
Property, plant and equipment	**(717)**	(828)
Risk management assets and liabilities, net	**(107)**	(141)
Employee future benefits and compensation plans	**62**	56
Interest deductible in future periods	**22**	42
Foreign exchange differences on US-denominated debt	**31**	40
Other deductible temporary differences	**2**	4
Net deferred income tax liability, before writedown of deferred income tax assets	**(98)**	(211)
Writedown of deferred income tax assets	**(247)**	(243)
Net deferred income tax liability, after writedown of deferred income tax assets	**(345)**	(454)

(1) Net operating losses expire between 2029 and 2039.

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

As at Dec. 31	2020	2019
Deferred income tax assets(1)	**51**	18
Deferred income tax liabilities	**(396)**	(472)
Net deferred income tax liability	**(345)**	(454)

(1) The deferred income tax assets presented on the Consolidated Statements of Financial Position are recoverable based on estimated future earnings and tax planning strategies. The assumptions used in the estimate of future earnings are based on the Corporation's long-range forecasts.

D. Contingencies

As of Dec. 31, 2020, the Corporation had recognized a net liability of nil (2019 – $1 million) related to uncertain tax positions.

13. Non-Controlling Interests

The Corporation's subsidiaries and operations that have non-controlling interests are as follows:

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2020
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.9% - Public shareholders
Kent Hills Wind LP(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

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

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

A. TransAlta Renewables

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

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders could elect to automatically reinvest monthly dividends into additional common shares of the Corporation. The Corporation does not participate in the DRIP.

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

As a result of the DRIP and the Share Offering described in Note 4(W), the Corporation's share of ownership and equity participation in TransAlta Renewables has changed as follows:

Period	**Ownership and voting rights percentage**	**Equity participation percentage**
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9
Jan. 1, 2019 to Mar. 31, 2019	60.8	60.8
April 1, 2019 to June 30, 2019	60.6	60.6
July 1, 2019 to Sept. 30, 2019	60.5	60.5
Oct. 1, 2019 to Dec. 31, 2019	60.4	60.4
Jan. 1, 2020 to Mar. 31, 2020	60.3	60.3
April 1, 2020 to June 30, 2020	60.2	60.2
July 1, 2020 to Dec. 31, 2020	60.1	60.1

Year ended Dec. 31	**2020**	2019	2018
Revenues	**436**	446	462
Net earnings	**97**	183	241
Total comprehensive income	**223**	138	281
Amounts attributable to the non-controlling interests:			
Net earnings	**40**	73	94
Total comprehensive income	**90**	56	110
Distributions paid to non-controlling interests	**80**	69	79

As at Dec. 31	**2020**	2019
Current assets	**743**	293
Long-term assets	**2,913**	3,409
Current liabilities	**(364)**	(152)
Long-term liabilities	**(987)**	(1,237)
Total equity	**(2,305)**	(2,313)
Equity attributable to non-controlling interests	**(948)**	(941)
Non-controlling interests' share (per cent)	**39.9**	39.6

B. TA Cogen

Year ended Dec. 31	2020	2019	2018
Results of operations			
Revenues	**146**	181	185
Net earnings (loss)	**(13)**	43	29
Total comprehensive income (loss)	**(13)**	43	29
Amounts attributable to the non-controlling interest:			
Net earnings (loss)	**(6)**	21	14
Total comprehensive income (loss)	**(6)**	21	14
Distributions paid to Canadian Power Holdings Inc.	**17**	37	86

As at Dec. 31	2020	2019
Current assets	**69**	41
Long-term assets	**323**	328
Current liabilities	**(78)**	(27)
Long-term liabilities	**(37)**	(19)
Total equity	**(277)**	(323)
Equity attributable to Canadian Power Holdings Inc.	**(136)**	(160)
Non-controlling interest share (per cent)	**49.99**	49.99

14. Trade and Other Receivables

As at Dec. 31	2020	2019
Trade accounts receivable	**488**	399
Collateral paid (Note 16)	**49**	42
Current portion of finance lease receivables (Note 8)	**36**	15
Income taxes receivable	**10**	6
Trade and other receivables	**583**	462

15. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

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

Carrying value as at Dec. 31, 2020

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

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

Carrying value as at Dec. 31, 2019

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Total
Financial assets				
Cash and cash equivalents[1]	–	–	411	411
Restricted cash	–	–	32	32
Trade and other receivables	–	–	462	462
Long-term portion of finance lease receivables	–	–	176	176
Risk management assets				
Current	71	95	–	166
Long-term	607	33	–	640
Other assets (Note 22)	–	–	47	47
Financial liabilities				
Accounts payable and accrued liabilities	–	–	413	413
Dividends payable	–	–	37	37
Risk management liabilities				
Current	1	80	–	81
Long-term	1	28	–	29
Credit facilities, long-term debt and lease liabilities[2]	–	–	3,212	3,212
Exchangeable securities (Note 25)	–	–	326	326

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

B. Fair Value of Financial Instruments

The fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair values can be determined by reference to prices for that instrument in active markets to which the Corporation has access. In the absence of an active market, the Corporation determines fair values based on valuation models or by reference to other similar products in active markets.

Fair values determined using valuation models require the use of assumptions. In determining those assumptions, the Corporation looks primarily to external readily observable market inputs. However, if not available, the Corporation uses inputs that are not based on observable market data.

I. Level I, II and III Fair Value Measurements

The Level I, II and III classifications in the fair value hierarchy utilized by the Corporation are defined below. The fair value measurement of a financial instrument is included in only one of the three levels, the determination of which is based on the lowest level input that is significant to the derivation of the fair value.

a. Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access at the measurement date. In determining Level I fair values, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange.

b. Level II

Fair values are determined, directly or indirectly, using inputs that are observable for the asset or liability.

Fair values falling within the Level II category are determined through the use of quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability, such as basis, credit valuation and location differentials.

The Corporation's commodity risk management Level II financial instruments include over-the-counter derivatives with values based on observable commodity futures curves and derivatives with inputs validated by broker quotes or other publicly available market data providers. Level II fair values are also determined using valuation techniques, such as option pricing models and interpolation formulas, where the inputs are readily observable.

In determining Level II fair values of other risk management assets and liabilities, the Corporation uses observable inputs other than unadjusted quoted prices that are observable for the asset or liability, such as interest rate yield curves and currency rates. For certain financial instruments where insufficient trading volume or lack of recent trades exists, the Corporation relies on similar interest or currency rate inputs and other third-party information such as credit spreads.

c. Level III

Fair values are determined using inputs for the assets or liabilities that are not readily observable.

The Corporation may enter into commodity transactions for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques such as mark-to-forecast and mark-to-model. For mark-to-model valuations, derivative pricing models, regression-based models and historical bootstrap models may be employed. The model inputs may be based on historical data such as unit availability, transmission congestion, demand profiles for individual non-standard deals and structured products, and/or volatilities and correlations between products derived from historical price relationships.

The Corporation also has various commodity contracts with terms that extend beyond a liquid trading period. As forward market prices are not available for the full period of these contracts, the value of these contracts is derived by reference to a forecast that is based on a combination of external and internal fundamental modelling, including discounting. As a result, these contracts are classified in Level III.

The Corporation has a Commodity Exposure Management Policy that governs both the commodity transactions undertaken in its proprietary trading business and those undertaken to manage commodity price exposures in its generation business. This Policy defines and specifies the controls and management responsibilities associated with commodity trading activities, as well as the nature and frequency of required reporting of such activities.

Methodologies and procedures regarding commodity risk management Level III fair value measurements are determined by the Corporation's risk management department. Level III fair values are primarily calculated within the Corporation's energy trading risk management system. These calculations are based on underlying contractual data as well as observable and non-observable inputs. Development of non-observable inputs requires the use of judgment. To ensure reasonability, system-generated Level III fair value measurements are reviewed and validated by the risk management and finance departments. Review occurs formally on a quarterly basis or more frequently if daily review and monitoring procedures identify unexpected changes to fair value or changes to key parameters.

Information on risk management contracts or groups of risk management contracts that are included in Level III measurements and the related unobservable inputs and sensitivities, is as follows, and excludes the effects on fair value of certain unobservable inputs such as liquidity and credit discount (described as "base fair values"), as well as inception gains or losses. Sensitivity ranges for the base fair values are determined using reasonably possible alternative assumptions for the key unobservable inputs, which may include forward commodity prices, commodity volatilities and correlations, delivery volumes and shapes.

As at				Dec. 31, 2020		
Description	**Base fair value**	**Sensitivity**	**Valuation technique**	**Unobservable input**	**Range**	**Reasonable possible change**
Long-term power sale – US	598	+35 -59	Long-term price forecast	Illiquid future power prices (per MWh)	US$24 to US$32	Price decrease of US$3 or price increase of US$5
Coal transportation – US	(16)	+3 -5	Numerical derivative valuation	Illiquid future power prices (per MWh) Volatility Rail rate escalation	US$24 to US$32 15% to 40% US$21 to US$24	Price decrease of US$3 or price increase of US$5 80% to 120% zero to 4%
Full requirements – Eastern US	11	+3 -3	Historical bootstrap	Volume Cost of supply		95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	(29)	+22 -22	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	US$35 to US$52 US$11	Price increase or decrease of US$6 Price increase or decrease of US$1
Others	(4)	+5 -5				

As at				Dec. 31, 2019		
Description	Base fair value	Sensitivity	Valuation technique	Unobservable input	Range	Reasonable possible change
Long-term power sale – US	737	+46 -139	Long-term price forecast	Illiquid future power prices (per MWh)	US$20 to US$28	Price decrease of US$3 or a price increase of US$9
Structured products – Eastern US	7	+2 -2	Option valuation techniques, historical bootstrap and historical price regression analysis	Basis relationship Non-standard shape factors	91% to 112% 63% to 116%	4% to 6% 4% to 10%
Full requirements –Eastern US	10	+3 -3	Historical bootstrap	Volume Cost of supply		95% to 105% (+/-) US$1 per MWh
Long-term wind energy sale – Eastern US	(28)	+20 -20	Long-term price forecast	Illiquid future power prices (per MWh) Illiquid future REC prices (per unit)	US$38 to US$60 US$9	Price increase or decrease of US$6 Price increase or decrease of US$1
Others	(6)	+8 -8				

i. Long-Term Power Sale – US

The Corporation has a long-term fixed price power sale contract in the US for delivery of power at the following capacity levels: 380 MW through Dec. 31, 2024, and 300 MW through Dec. 31, 2025. The contract is designated as an all-in-one cash flow hedge.

For periods beyond 2022, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast.

The contract is denominated in US dollars. With the weakening of the US dollar relative to the Canadian dollar from Dec. 31, 2019, to Dec. 31, 2020, the base fair value and the sensitivity values have decreased by approximately $14 million and $1 million, respectively.

ii. Structured Products – Eastern US

The Corporation has structured fixed priced power in the eastern United States. Under these contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. As at Dec. 31, 2020, the Corporation did not have any material open positions on structured fixed priced power contracts.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data.

iii. Coal Transportation - US

The Corporation has a coal rail transport agreement that includes an upside sharing mechanism, with a contract start date of Jan. 1, 2021, and extending until Dec. 31, 2025. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.

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

For periods beyond 2022, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Option volatility and rail rate escalation ranges have been determined based on historical data and professional judgement.

iv. Full Requirements – Eastern US

The Corporation has a portfolio of full requirement service contracts, whereby the Corporation agrees to supply specific utility customer needs for a range of products that may include electrical energy, capacity, transmission, ancillary services, renewable energy credits and independent system operator costs.

The key unobservable inputs used in the portfolio valuation include delivered volume and supply cost. Hourly shaping of consumption will result in a realized cost that may be at a premium (or discount) relative to the average settled price. Reasonable possible alternative inputs are used to determine sensitivity on the fair value measurement.

v. Long-Term Wind Energy Sale – Eastern US

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

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

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2020, are as follows: Level I – $13 million net liability (Dec. 31, 2019 – $3 million net liability), Level II – $27 million net liability (Dec. 31, 2019 – $9 million net asset) and Level III – $582 million net asset (Dec. 31, 2019 – $686 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2020, are primarily attributable to contract settlements, unfavourable changes in market prices and unfavourable changes in foreign exchange rates.

The following tables summarize the key factors impacting the fair value of the Level III commodity risk management assets and liabilities by classification level during the years ended Dec. 31, 2020 and 2019, respectively:

	Year ended Dec. 31, 2020			Year ended Dec. 31, 2019		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**678**	**8**	**686**	689	6	695
Changes attributable to:						
Market price changes on existing contracts	**(18)**	**3**	**(15)**	77	8	85
Market price changes on new contracts	**—**	**7**	**7**	—	14	14
Contracts settled	**(71)**	**(10)**	**(81)**	(57)	(19)	(76)
Change in foreign exchange rates	**(16)**	**1**	**(15)**	(31)	(1)	(32)
Transfers into (out of) Level III	**—**	**—**	**—**	—	—	—
Net risk management assets at end of period	**573**	**9**	**582**	678	8	686
Additional Level III information:						
Gains (losses) recognized in other comprehensive income	**(34)**	**—**	**(34)**	46	—	46
Total gains included in earnings before income taxes	**71**	**11**	**82**	57	21	78
Unrealized gains included in earnings before income taxes relating to net assets held at period end	**—**	**1**	**1**	—	2	2

III. Other Risk Management Assets and Liabilities

Other risk management assets and liabilities primarily include risk management assets and liabilities that are used in managing exposures on non-energy marketing transactions such as interest rates, the net investment in foreign operations and other foreign currency risks. Hedge accounting is not always applied.

Other risk management assets and liabilities with a total net liability fair value of $12 million as at Dec. 31, 2020 (Dec. 31, 2019 – $4 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets and liabilities during the year ended Dec. 31, 2020, are primarily attributable to favorable market prices on existing contracts.

IV. Other Financial Assets and Liabilities

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

	Fair value(1)				**Total carrying value(1)**
	Level I	**Level II**	**Level III**	**Total**	
Exchangeables securities – Dec. 31, 2020	**—**	**769**	**—**	**769**	**730**
Long-term debt – Dec. 31, 2020	**—**	**3,480**	**—**	**3,480**	**3,227**
Exchangeable securities – Dec. 31, 2019	—	342	—	342	326
Long-term debt – Dec. 31, 2019	—	3,157	—	3,157	3,070

(1) Includes current portion.

The fair values of the Corporation's debentures, senior notes and exchangeable securities are determined using prices observed in secondary markets. Non-recourse and other long-term debt fair values are determined by calculating an implied price based on a current assessment of the yield to maturity.

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, restricted cash, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 22) and the finance lease receivables (see Note 8) approximate the carrying amounts.

C. Inception Gains and Losses

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

As at Dec. 31	2020	2019	2018
Unamortized net gain at beginning of year	**9**	49	105
New inception gains (losses)(1)	**(13)**	3	(14)
Change in foreign exchange rates	**—**	—	5
Amortization recorded in net earnings during the year	**(29)**	(43)	(47)
Unamortized net gain (loss) at end of year(2)	**(33)**	9	49

(1) During 2020, the Corporation entered into a coal rail transportation agreement that includes an upside sharing mechanism. Option pricing techniques have been utilized to value the obligation associated with this component of the deal.
(2) During 2020, the net inception gain on the long-term fixed price power sale contract in the US changed to a loss position based on the day 1 forward price curve at inception of the contract.

16. Risk Management Activities

A. Risk Management Strategy

The Corporation is exposed to market risk from changes in commodity prices, foreign exchange rates, interest rates, credit risk and liquidity risk. These risks affect the Corporation's earnings and the value of associated financial instruments that the Corporation holds. In certain cases, the Corporation seeks to minimize the effects of these risks by using derivatives to hedge its risk exposures. The Corporation's risk management strategy, policies and controls are designed to ensure that the risks it assumes comply with the Corporation's internal objectives and its risk tolerance.

The Corporation has two primary streams of risk management activities: i) financial exposure management and ii) commodity exposure management. Within these activities, risks identified for management include commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk.

The Corporation seeks to minimize the effects of commodity risk, interest rate risk and foreign currency risk by using derivative financial instruments to hedge risk exposures. Of these derivatives, the Corporation may apply hedge accounting to those hedging commodity price risk and foreign currency risk.

The use of financial derivatives is governed by the Corporation's policies approved by the Board, which provide written principles on commodity risk, interest rate risk, liquidity risk, equity price risk and foreign currency risk, as well as the use of financial derivatives and non-derivative financial instruments.

Liquidity risk, credit risk and equity price risk are managed through means other than derivatives or hedge accounting.

The Corporation enters into various derivative transactions as well as other contracting activities that do not qualify for hedge accounting or where a choice was made not to apply hedge accounting. As a result, the related assets and liabilities are classified as derivatives at fair value through profit and loss. The net realized and unrealized gains or losses from changes in the fair value of these derivatives are reported in net earnings in the period the change occurs.

The Corporation designates certain derivatives as hedging instruments to hedge commodity price risk, foreign currency exchange risk in cash flow hedges, and hedges of net investments in foreign operations. Hedges of foreign exchange risk on firm commitments are accounted for as cash flow hedges.

At the inception of the hedge relationship, the Corporation documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. At the inception of the hedge and on an ongoing basis, the Corporation also documents whether the hedging instrument is effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk, which is when the hedging relationships meet all of the following hedge effectiveness requirements:

- There is an economic relationship between the hedged item and the hedging instrument;
- The effect of credit risk does not dominate the value changes that result from that economic relationship; and
- The hedge ratio of the hedging relationship is the same as that resulting from the quantity of the hedged item that the Corporation actually hedges and the quantity of the hedging instrument that the entity actually uses to hedge that quantity of hedged item.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Corporation adjusts the hedge ratio of the hedging relationship so that it continues to meet the qualifying criteria.

B. Net Risk Management Assets and Liabilities

Aggregate net risk management assets and (liabilities) are as follows:

As at Dec. 31, 2020

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

As at Dec. 31, 2019

	Cash flow hedges	Not designated as a hedge	Total
Commodity risk management			
Current	70	15	85
Long-term	606	1	607
Net commodity risk management assets	676	16	692
Other			
Current	—	—	—
Long-term	—	4	4
Net other risk management assets	—	4	4
Total net risk management assets	676	20	696

I. Netting Arrangements

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at Dec. 31	2020				2019			
	Current financial assets	**Long-term financial assets**	**Current financial liabilities**	**Long-term financial liabilities**	Current financial assets	Long-term financial assets	Current financial liabilities	Long-term financial liabilities
Gross amounts recognized	**120**	**69**	**(132)**	**(104)**	316	631	(191)	(100)
Gross amounts set-off	**(69)**	**(10)**	**69**	**10**	(140)	(42)	140	42
Net amounts as included in the Consolidated Statements of Financial Position	**51**	**59**	**(63)**	**(94)**	176	589	(51)	(58)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

The Corporation has exposure to movements in certain commodity prices in both its electricity generation and proprietary trading businesses, including the market price of electricity and fuels used to produce electricity. Most of the Corporation's electricity generation and related fuel supply contracts are considered to be contracts for delivery or receipt of a non-financial item in accordance with the Corporation's expected own use requirements and are not considered to be financial instruments. As such, the discussion related to commodity price risk is limited to the Corporation's proprietary trading business and commodity derivatives used in hedging relationships associated with the Corporation's electricity generating activities.

To mitigate the risk of adverse commodity price changes, the Corporation uses three tools:

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

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

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

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

i. Commodity Price Risk Management – Proprietary Trading

The Corporation's Energy Marketing segment conducts proprietary trading activities and uses a variety of instruments to manage risk, earn trading revenue and gain market information.

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including VaR limits. The Board approves the limit for total VaR from proprietary trading activities. VaR is the most commonly used metric employed to track and manage the market risk associated with trading positions. A VaR measure gives, for a specific confidence level, an estimated maximum pre-tax loss that could be incurred over a specified period of time. VaR is used to determine the potential change in value of the Corporation's proprietary trading portfolio, over a three-day period within a 95 per cent confidence level, resulting from normal market fluctuations. VaR is estimated using the historical variance/covariance approach. VaR is a measure that has certain inherent limitations. The use of historical information in the estimate assumes that price movements in the past will be indicative of future market risk. As such, it may only be meaningful under normal market conditions. Extreme market events are not addressed by this risk measure. In addition, the use of a three-day measurement period implies that positions can be unwound or hedged within three days, although this may not be possible if the market becomes illiquid.

Changes in market prices associated with proprietary trading activities affect net earnings in the period that the price changes occur. VaR at Dec. 31, 2020, associated with the Corporation's proprietary trading activities was $1 million (2019 — $1 million, 2018 — $2 million).

ii. Commodity Price Risk – Generation

The generation segments utilize various commodity contracts to manage the commodity price risk associated with electricity generation, fuel purchases, emissions and byproducts, as considered appropriate. A Commodity Exposure Management Policy is prepared and approved annually, which outlines the intended hedging strategies associated with the Corporation's generation assets and related commodity price risks. Controls also include restrictions on authorized instruments, management reviews on individual portfolios and approval of asset transactions that could add potential volatility to the Corporation's reported net earnings.

TransAlta has entered into various contracts with other parties whereby the other parties have agreed to pay a fixed price for electricity to TransAlta. While not all of the contracts create an obligation for the physical delivery of electricity to other parties, the Corporation has the intention and believes it has sufficient electrical generation available to satisfy these contracts and, where able, has designated these as cash flow hedges for accounting purposes. As a result, changes in market prices associated with these cash flow hedges do not affect net earnings in the period in which the price change occurs. Instead, changes in fair value are deferred until settlement through AOCI, at which time the net gain or loss resulting from the combination of the hedging instrument and hedged item affects net earnings.

VaR at Dec. 31, 2020, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $12 million (2019 — $25 million, 2018 — $18 million). For positions and economic hedges that do not meet hedge accounting requirements or for short-term optimization transactions such as buybacks entered into to offset existing hedge positions, these transactions are marked to the market value with changes in market prices associated with these transactions affecting net earnings in the period in which the price change occurs. VaR at Dec. 31, 2020, associated with these transactions was $15 million (2019— $8 million, 2018 — $13 million).

iii. Commodity Price Risk Management – Hedges

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

As at Dec. 31	**2020**		2019	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*[(1)]	**95**	**—**	222	—

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

During 2020, unrealized pre-tax gains of $1 million (2019 — $1 million, 2018 — $4 million) related to certain power hedging relationships that were previously de-designated and deemed ineffective for accounting purposes were released from AOCI and recognized in net earnings.

iv. Commodity Price Risk Management – Non-Hedges

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

As at Dec. 31	**2020**		2019	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**12,944**	**8,258**	16,097	7,204
Natural gas *(GJ)*	**23,035**	**177,448**	38,062	55,023
Transmission *(MWh)*	**—**	**1,578**	—	1,818
Emissions *(MWh)*	**1,831**	**2,112**	184	138
Emissions *(tonnes)*	**2,160**	**2,365**	2,436	2,446

b. Interest Rate Risk Management

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

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represent 7 per cent of the Corporation’s debt as at Dec. 31, 2020 (2019 – 11 per cent). Interest rate risk is managed with the use of derivatives. The Corporation's outstanding interest rate derivative instruments are as follows.

At Dec. 31, 2020, the Corporation had interest rate swap agreements in place with a notional amount of US$150 million whereby the Corporation receives a variable rate of interest equal to the three-month LIBOR rate and pays interest at a fixed rate equal to 0.94 per cent on the notional amount. The swap is being used to hedge interest rate exposure on a highly probable future US$400 million fixed rate debt issuance.

At Dec. 31, 2020, the Corporation had a bond lock agreement in place with a notional amount of $75 million whereby on the pricing date, if the difference between the underlying 5.75 per cent Government of Canada bond and the forward bond price of $150 million (forward yield 1.20 per cent) is positive, the Corporation receives settlement. If the difference is negative, the Corporation pays settlement. The swap is being used to hedge interest rate exposure on a highly probable future $150 million fixed rate debt issuance.

There were no interest rate derivative instruments outstanding in 2019 or 2018.

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

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

c. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar and the Australian dollar, as a result of investments and operations in foreign jurisdictions, the net earnings from those operations and the acquisition of equipment and services from foreign suppliers.

The Corporation may enter into the following hedging strategies to mitigate currency rate risk, including:

- Foreign exchange forward contracts to mitigate adverse changes in foreign exchange rates on project-related expenditures and distributions received in foreign currencies;
- Foreign exchange forward contracts and cross-currency swaps to manage foreign exchange exposure on foreign-denominated debt not designated as a net investment hedge; and
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

The Corporation's target is to hedge a minimum of 60 per cent of our forecasted foreign operating cash flows over a four-year period, with a minimum of 90 per cent in the current year, 70 per cent in the next year, 50 per cent in the third year and 30 per cent in the fourth year. The US exposure will be managed with a combination of interest expense on our US-denominated debt and forward foreign exchange contracts and the Australian exposure will be managed with a combination of interest expense on our Australian-dollar denominated debt and forward foreign exchange contracts.

i. Net Investment Hedges
When designating foreign currency debt as a hedge of the Corporation’s net investment in foreign subsidiaries, the Corporation has determined that the hedge is effective if the foreign currency of the net investment is the same as the currency of the hedge, and therefore an economic relationship is present.

The Corporation’s hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$370 million (2019 — US$370 million).

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

As at Dec. 31	2020				2019			
	Notional amount sold	**Notional amount purchased**	**Fair value liability**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset	Maturity
Foreign Exchange Forward Contracts - foreign-denominated receipts/expenditures								
	CAD71	**USD54**	**(2)**	**2021**	CAD124	USD95	—	2020-2021

iii. Non-Hedges

As part of the sale of the Corporation's economic interest in the Australian Assets to TransAlta Renewables, the Corporation agreed to mitigate the risks to TransAlta Renewables' shareholders of adverse changes in the US and Australian in respect of cash flows from the Australian Assets in relation to the Canadian dollar to June 30, 2020. The financial effects of the agreements eliminate on consolidation.

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts.

The Corporation also uses foreign currency contracts to manage its expected foreign operating cash flows. Hedge accounting is not applied to these foreign currency contracts.

As at Dec. 31	2020				2019			
	Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount sold	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts – foreign-denominated receipts/expenditures								
	AUD197	**CAD181**	**(14)**	**2021-2024**	AUD286	CAD266	—	2020 - 2023
	USD47	**CAD72**	**9**	**2021-2024**	USD108	CAD139	(4)	2020 - 2023
	AUD4	**USD3**	**—**	**2021**				
	CAD1	**EUR1**	**—**	**2021**				
Foreign exchange forward contracts – foreign-denominated debt								
	CAD191	USD150	2	**2022**	CAD191	USD150	6	2022

iv. Impacts of currency rate risk

The possible effect on net earnings and OCI, due to changes in foreign exchange rates associated with financial instruments denominated in currencies other than the Corporation's functional currency, is outlined below. The sensitivity analysis has been prepared using management's assessment that an average three cent (2019 — three cent, 2018 — four cent) increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next quarter.

Year ended Dec. 31	2020		2019		2018	
Currency	**Net earnings increase (decrease)(1)**	**OCI gain(1),(2)**	Net earnings increase(1)	OCI gain(1),(2)	Net earnings decrease(1)	OCI gain(1),(2)
USD	**(8)**	**1**	(18)	2	(13)	—
AUD	**(4)**	**—**	(6)	—	(7)	—
Total	**(12)**	**1**	(24)	2	(20)	—

(1) These calculations assume an increase in the value of these currencies relative to the Canadian dollar. A decrease would have the opposite effect.
(2) The foreign exchange impact related to financial instruments designated as hedging instruments in net investment hedges has been excluded.

II. Credit Risk

Credit risk is the risk that customers or counterparties will cause a financial loss for the Corporation by failing to discharge their obligations, and the risk to the Corporation associated with changes in creditworthiness of entities with which commercial exposures exist. The Corporation actively manages its exposure to credit risk by assessing the ability of counterparties to fulfil their obligations under the related contracts prior to entering into such contracts. The Corporation makes detailed assessments of the credit quality of all counterparties and, where appropriate, obtains corporate guarantees, cash collateral, third-party credit insurance and/or letters of credit to support the ultimate collection of these receivables. For commodity trading and origination, the Corporation sets strict credit limits for each counterparty and monitors exposures on a daily basis. TransAlta uses standard agreements that allow for the netting of exposures and often include margining provisions. If credit limits are exceeded, TransAlta will request collateral from the counterparty or halt trading activities with the counterparty.

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2020:

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

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

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on segment historical rates of default of trade receivables as well as incorporating forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward-looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2020.

The Corporation's maximum exposure to credit risk at Dec. 31, 2020, without taking into account collateral held or right of set-off, is represented by the current carrying amounts of receivables and risk management assets as per the Consolidated Statements of Financial Position. Letters of credit and cash are the primary types of collateral held as security related to these amounts. The maximum credit exposure to any one customer for commodity trading operations and hedging, including the fair value of open trading, net of any collateral held, at Dec. 31, 2020, was $22 million (2019 — $5 million).

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

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

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

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. As at Dec. 31, 2020, TransAlta maintains an investment grade rating from one credit rating agency and below investment grade ratings from two credit rating agencies. Between 2021 and 2023, the Corporation has approximately $1 billion of debt maturing, comprised of approximately $631 million of recourse debt, with the balance mainly related to scheduled non-recourse debt repayments. We expect to refinance the debt maturing in 2022.

Collateral is posted based on negotiated terms with counterparties, which can include the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

TransAlta manages liquidity risk by monitoring liquidity on trading positions; preparing and revising longer-term financing plans to reflect changes in business plans and the market availability of capital; reporting liquidity risk exposure for proprietary trading activities on a regular basis to the Risk Management Committee, senior management and the Board; and maintaining sufficient undrawn committed credit lines to support potential liquidity requirements. The Corporation does not use derivatives or hedge accounting to manage liquidity risk.

A maturity analysis of the Corporation's financial liabilities is as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Accounts payable and accrued liabilities	599	—	—	—	—	—	599
Long-term debt(1)	96	626	277	119	136	2,010	3,264
Exchangeable securities(2)	—	—	—	—	750	—	750
Commodity risk management (assets) liabilities	(92)	(87)	(131)	(131)	(103)	2	(542)
Other risk management (assets) liabilities	14	—	1	(2)	—	(1)	12
Lease liabilities(3)	(5)	6	5	5	5	118	134
Interest on long-term debt and lease liabilities(4)	161	153	126	119	113	893	1,565
Interest on exchangeable securities(2, 4)	53	52	53	52	—	—	210
Dividends payable	59	—	—	—	—	—	59
Total	**885**	**750**	**331**	**162**	**901**	**3,022**	**6,051**

(1) Excludes impact of hedge accounting and derivatives.
(2) Assumes the exchangeable securities will be exchanged on Jan. 1, 2025. Refer to Note 25 for further details.
(3) Lease liabilities include a lease incentive of $13 million, expected to be received in 2021.
(4) Not recognized as a financial liability on the Consolidated Statements of Financial Position.

IV. Equity Price Risk

a. Total Return Swaps

The Corporation has certain compensation, deferred and restricted share unit programs, the values of which depend on the common share price of the Corporation. The Corporation has fixed a portion of the settlement cost of these programs by entering into a total return swap for which hedge accounting has not been applied. The total return swap is cash settled every quarter based upon the difference between the fixed price and the market price of the Corporation's common shares at the end of each quarter.

D. Hedging Instruments – Uncertainty of Future Cash Flows

The following table outlines the terms and conditions of derivative hedging instruments and how they affect the amount, timing and uncertainty of future cash flows:

	Maturity					
	2021	2022	2023	2024	2025	2026 and thereafter
Cash flow hedges(1)						
Foreign currency forward contracts						
Notional amount ($ millions)						
CAD/USD	54	—	—	—	—	—
Average Exchange Rate						
CAD/USD	0.7648	—	—	—	—	—
Commodity derivative instruments						
Electricity						
Notional amount (thousands MWh)	3,424	3,329	3,329	3,338	2,628	—
Average Price ($ per MWh)	69.51	71.91	73.72	75.56	77.44	—

(1) The interest rate swaps detailed above both settle in 2021.

E. Effects of Hedge Accounting on the Financial Position and Performance

I. Effect of Hedges

The impact of the hedging instruments on the statement of financial position is as follows:

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

As at Dec. 31, 2019	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	19 MMWh	678	Risk management assets	47
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD370	CAD483	Credit facilities, long-term debt and lease liabilities	21

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

As at Dec. 31	2020		2019	
	Change in fair value used for measuring ineffectiveness	**Cash flow hedge reserve(1)**	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve(1)
Commodity price risk				
Cash flow hedges				
Power forecast sales – Centralia	**(33)**	**417**	47	527
Interest rate risk				
Cash flow hedges				
Interest expense on long-term debt	**7**	**19**	—	—
	Change in fair value used for measuring ineffectiveness	**Foreign currency translation reserve(1)**	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve(1)
Foreign currency risk				
Net investment hedges				
Net investment in foreign subsidiaries	**11**	**(21)**	21	(21)

(1) Included in AOCI.

The hedging gain recognized in OCI before tax is equal to the change in fair value used for measuring effectiveness for the net investment hedge. There is no ineffectiveness recognized in profit or loss.

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

		Year ended Dec. 31, 2020			
		Effective portion		**Ineffective portion**	
Derivatives in cash flow hedging relationships	**Pre-tax gain (loss) recognized in OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss reclassified from OCI**	**Location of (gain) loss reclassified from OCI**	**Pre-tax (gain) loss recognized in earnings**
Commodity contracts	**41**	Revenue	**(137)**	Revenue	**—**
Foreign exchange forwards on project hedges	**(1)**	Property, plant and equipment	**—**	Foreign exchange (gain) loss	**—**
Forward starting interest rate swaps	**(12)**	Interest expense	**(4)**	Interest expense	**—**
OCI impact	**28**	**OCI impact**	**(141)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $72 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

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

Year ended Dec. 31, 2018					
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	(9)	Revenue	(67)	Revenue	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	(9)	OCI impact	(57)	Net earnings impact	—

II. Effect of Non-Hedges

For the year ended Dec. 31, 2020, the Corporation recognized a net unrealized gain of $43 million (2019 — gain of $33 million, 2018 — loss of $29 million) related to commodity derivatives.

For the year ended Dec. 31, 2020, a gain of $11 million (2019 — gain of $24 million, 2018 —gain of $3 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized loss of $2 million (2019 — gains of $6 million, 2018 — gains of $4 million) and net realized gains of $13 million (2019 — gains of $18 million, 2018 — losses of $1 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2020, the Corporation provided $49 million (2019 – $42 million) in cash and cash equivalents as collateral to regulated clearing agents as security for commodity trading activities. These funds are held in segregated accounts by the clearing agents. Collateral provided is included in accounts receivable in the Consolidated Statements of Financial Position.

II. Financial Assets Held as Collateral

At Dec. 31, 2020, the Corporation held nil (2019 – $3 million) in cash collateral associated with counterparty obligations. Under the terms of the contracts, the Corporation may be obligated to pay interest on the outstanding balances and to return the principal when the counterparties have met their contractual obligations or when the amount of the obligation declines as a result of changes in market value. Interest payable to the counterparties on the collateral received is calculated in accordance with each contract. Collateral held is included in accounts payable in the Consolidated Statements of Financial Position.

III. Contingent Features in Derivative Instruments

Collateral is posted in the normal course of business based on the Corporation's senior unsecured credit rating as determined by certain major credit rating agencies. Certain of the Corporation's derivative instruments contain financial assurance provisions that require collateral to be posted only if a material adverse credit-related event occurs.

As at Dec. 31, 2020, the Corporation had posted collateral of $163 million (Dec. 31, 2019 – $112 million) in the form of letters of credit on derivative instruments in a net liability position. Certain derivative agreements contain credit-risk-contingent features, which if triggered could result in the Corporation having to post an additional $85 million (Dec. 31, 2019 – $51 million) of collateral to its counterparties.

17. Inventory

Inventory held in the normal course of business, which includes coal, emission credits, parts and materials, and natural gas, is valued at the lower of cost and net realizable value. Inventory held for trading, which includes natural gas and emission credits and allowances, is valued at fair value less costs to sell.

In the third quarter of 2020, the Corporation adjusted the useful life of its Highvale mine assets to align with the Corporation's conversion to gas plans. The standard cost of coal has increased as a result of the increased depreciation costs, in addition to reduced coal consumption. As the cost is not expected to be recovered based on current power pricing, the Corporation recognized a $37 million writedown to net realizable value on its internally produced coal inventory for the year ended Dec. 31, 2020.

The components of inventory are as follows:

As at Dec. 31	**2020**	2019
Parts and materials	**107**	108
Coal	**83**	130
Deferred stripping costs	**8**	6
Natural gas	**2**	3
Purchased emission credits(1)	**38**	4
Total	**238**	251

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

The change in inventory is as follows:

Balance, Dec. 31, 2018	242
Net addition	12
Change in foreign exchange rates	(3)
Balance, Dec. 31, 2019	251
Net addition	**26**
Writedowns	**(37)**
Change in foreign exchange rates	**(2)**
Balance, Dec. 31, 2020	**238**

No inventory is pledged as security for liabilities.

The Corporation purchases emissions credits and also generates emissions credits from its Wind and Solar and Hydro segments. Emission credits generated from our business have no recorded book value but will be used to offset other emissions obligations in the future, resulting in reduced fuel compliance costs. At Dec. 31, 2020, we currently hold 1,434,761 purchased emission credits (2019 — 388,155) recorded at $38 million (2019 — $4 million) and approximately 502,653 (2019 — 411,115) emission credits with no recorded book value.

18. Property, Plant and Equipment

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

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2018	94	5,937	1,964	3,286	1,338	200	383	13,202
Adjustments on implementation of IFRS 16	—	—	—	(7)	(101)	—	—	(108)
Additions	—	—	—		—	407	115	522
Acquisitions (Note 4(R) and 4(T))[2]	—	300	—	—	—	139	—	439
Disposals[3]	(2)	(389)	(260)	—	(34)	—	(19)	(704)
(Impairment) reversals (Note 7)	—	448	—	(2)	(15)	—	—	431
Revisions and additions to decommissioning and restoration costs (Note 23)	—	(62)	11	2	26	—	—	(23)
Retirement of assets	—	(158)	(26)	(7)	(10)	—	—	(201)
Change in foreign exchange rates	(1)	(63)	(40)	(17)	(3)	(4)	(6)	(134)
Transfers[4]	—	103	22	319	25	(514)	16	(29)
As at Dec. 31, 2019	91	6,116	1,671	3,574	1,226	228	489	13,395
Additions	**—**	**—**	**—**	**—**	**—**	**478**	**8**	**486**
Acquisitions (Note 4(K))	**—**	**—**	**1**	**—**	**—**	**—**	**—**	**1**
Disposals	**(2)**	**(1)**	**—**	**—**	**—**	**—**	**(2)**	**(5)**
Impairment (Note 7)	**(9)**	**(69)**	**—**	**(2)**	**—**	**—**	**(1)**	**(81)**
Revisions and additions to decommissioning and restoration costs (Note 23)	**—**	**21**	**(11)**	**8**	**76**	**—**	**—**	**94**
Retirement of assets	**—**	**(35)**	**(12)**	**(7)**	**(3)**	**—**	**(1)**	**(58)**
Change in foreign exchange rates	**(1)**	**(37)**	**45**	**(14)**	**(2)**	**—**	**6**	**(3)**
Transfers[4]	**17**	**142**	**(263)**	**33**	**(29)**	**(211)**	**(120)**	**(431)**
As at Dec. 31, 2020	**96**	**6,137**	**1,431**	**3,592**	**1,268**	**495**	**379**	**13,398**
Accumulated depreciation								
As at Dec. 31, 2018	—	3,765	1,128	1,161	830	—	154	7,038
Adjustments on implementation of IFRS 16	—	—	—	(3)	(43)	—	—	(46)
Depreciation	—	304	77	136	97	—	16	630
Retirement of assets	—	(158)	(23)	(3)	(6)	—	—	(190)
Disposals[3]	—	(170)	(255)	—	(14)	—	—	(439)
Impairment reversal (Note 7)	—	297	—	—	—	—	—	297
Change in foreign exchange rates	—	(52)	(16)	(4)	(2)	—	(2)	(76)
Transfers	—	10	(11)	(3)	(22)	—	—	(26)
As at Dec. 31, 2019	—	3,996	900	1,284	840	—	168	7,188
Depreciation	**—**	**352**	**76**	**142**	**133**	**—**	**14**	**717**
Retirement of assets	**—**	**(31)**	**(10)**	**(6)**	**(4)**	**—**	**—**	**(51)**
Disposals	**—**	**(1)**	**—**	**—**	**—**	**—**	**(1)**	**(2)**
Change in foreign exchange rates	**—**	**(35)**	**18**	**(4)**	**(2)**	**—**	**2**	**(21)**
Transfers	**—**	**—**	**(212)**	**—**	**(29)**	**—**	**(14)**	**(255)**
As at Dec. 31, 2020	**—**	**4,281**	**772**	**1,416**	**938**	**—**	**169**	**7,576**
Carrying amount								
As at Dec. 31, 2018	94	2,172	836	2,125	508	200	229	6,164
As at Dec. 31, 2019	91	2,120	771	2,290	386	228	321	6,207
As at Dec. 31, 2020	**96**	**1,856**	**659**	**2,176**	**330**	**495**	**210**	**5,822**

(1) Includes major spare parts and stand-by equipment available, but not in service, and spare parts used for routine, preventive or planned maintenance, and the Australian gas pipeline.

(2) 2019 includes $308 million related to the acquisition of the Keephills 3 facility with $300 million included in coal generation and the remainder in assets under construction.

(3) In 2019, we sold the Genesee 3 facility and sold the major components of the Mississauga facility. In addition, Centralia sold boiler parts included in capital spares and other for a net loss of $17 million. The Highvale mine also sold trucks included in mining property and equipment for a net loss of $18 million. Both were recognized in other gains on the statement of earnings (loss).

(4) 2020 transfers out of PP&E mainly relate to removing the Southern Cross assets from PP&E to a finance lease receivable and moving the Pioneer Pipeline and mine equipment to assets held for sale. 2020 transfers between the classifications of PP&E relate to the Centralia land purchase, the Sundance Unit 6 conversion to gas, the WindCharger project and planned major maintenance. 2019 transfers mainly relate to transferring the Pioneer Pipeline and US Wind Projects from assets under construction to coal generation and renewable generation, respectively.

Additions in 2020 included cash additions related to the conversions to gas of $93 million, the Windrise wind project of $156 million, the WindCharger battery storage project of $6 million, the Kaybob cogeneration project of $31 million, Centralia mine land of $17 million and planned major maintenance expenditures. Additions in 2019 included cash additions of $417 million (including $169 million related to the construction of the US Wind Projects), $100 million related to the Pioneer Pipeline (including $15 million transferred from other assets) and $5 million related to the Keephills 3 and Genesee 3 asset swap. Refer to Note 4 for further details of these transactions.

Depreciation expense increased mainly as a result of decisions to accelerate the Highvale mine shutdown to align with our conversion to gas plans, reflecting our transition away from coal. Depreciation expense also increased due to the Keephills 3 and Genesee 3 swap, the reversal of the impairment at Centralia and the changes in useful lives, all of which were effective in the second half of 2019. For further details on these changes, refer to Note 3(A)(III) and Note 4(R).

In 2020, the Corporation capitalized $8 million (2019 — $6 million) of interest to PP&E in at a weighted average rate of 6.0 per cent (2019 —5.9 per cent).

19. Right-of-Use Assets

The Corporation leases various properties and types of equipment. Lease contracts are typically made for fixed periods. Leases are negotiated on an individual basis and contain a wide range of terms and conditions. The lease agreements do not impose covenants, but leased assets may not be used as security for borrowing purposes.

A reconciliation of the changes in the carrying amount of the right-of-use assets is as follows:

	Land	Buildings	Vehicles	Equipment	Pipeline	Total
New leases recognized Jan. 1, 2019	29	22	1	—	—	52
Adjustments on recognition[(1)]	(1)	(4)	—	—	—	(5)
Transfers from PP&E, intangibles and other assets	—	—	3	35	—	38
As at Jan. 1, 2019	28	18	4	35	—	85
Additions	32	2	—	2	45	81
Depreciation	(1)	(4)	(2)	(11)	—	(18)
Changes in foreign exchange rates	(1)	—	—	—	—	(1)
Transfers	—	—	—	(1)	—	(1)
As at Dec. 31, 2019	58	16	2	25	45	146
Additions	**3**	**13**	**—**	**—**	**—**	**16**
Depreciation	**(3)**	**(5)**	**(1)**	**(9)**	**(3)**	**(21)**
As at Dec. 31, 2020	**58**	**24**	**1**	**16**	**42**	**141**

(1) Adjusted by the amount of any prepaid or accrued lease payments, onerous contract provisions and lease inducements.

In November 2019, the Corporation recognized a right-of-use asset and corresponding lease liability related to the initial 15-year term of its contract for transporting natural gas on the Pioneer Pipeline. The transportation contract provides the Corporation with the right to extend the contract for up to eight additional renewal periods of 24-months each. The amounts recognized represent the 50 per cent of the pipeline that is not owned by the Corporation.

In December 2019, the Corporation recognized an additional $31 million of right-of-use assets and $31 million of lease liabilities for land leases at certain wind facilities as a result of revised interpretations of the unit of account identified asset concepts present in IFRS 16.

For the year ended Dec. 31, 2020, TransAlta paid $33 million (2019 — $25 million) related to recognized lease liabilities, consisting of $8 million in interest (2019 —$4 million) and $25 million (2019 — $21 million) in principal repayments.

For the year ended Dec. 31, 2020, the Corporation expensed nil related to short-term (2019 — $2 million) and nil related to low-value leases (2019 — $1 million). Short-term leases (term of less than 12 months) and leases with total lease payments below the Corporation's capitalization threshold do not require recognition as lease liabilities and right-of-use assets.

Some of the Corporation's land leases that met the definition of a lease were not recognized as they require variable payments based on production or revenue. Additionally, certain land leases require payments to be made on the basis of the greater of the minimum fixed payments and variable payments based on production or revenue. For these leases, lease liabilities have been recognized on the basis of the minimum fixed payments. For the year ended Dec. 31, 2020, the Corporation expensed $7 million (2019 — $6 million) in variable land lease payments for these leases. For further information regarding leases refer to Note 5, 11, 24 and 36.

20. Intangible Assets

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

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2018	185	339	237	46	807
Assets transferred to right-of-use assets on implementation of IFRS 16 (Note 19)	—	(5)	—	—	(5)
Additions	—	—	—	14	14
Acquisition	—	1	—	15	16
Disposals (Note 4(R))	(37)	(1)	—	—	(38)
Change in foreign exchange rates	—	(4)	(1)	(1)	(6)
Transfers	1	48	14	(63)	—
As at Dec. 31, 2019	149	378	250	11	788
Additions	**—**	**—**	**—**	**14**	**14**
Acquisition (Note 4(K))	**—**	**—**	**37**	**—**	**37**
Disposals	**—**	**(1)**	**—**	**—**	**(1)**
Change in foreign exchange rates	**—**	**—**	**(2)**	**—**	**(2)**
Transfers	**—**	**35**	**(16)**	**(22)**	**(3)**
As at Dec. 31, 2020	**149**	**412**	**269**	**3**	**833**
Accumulated amortization					
As at Dec. 31, 2018	117	221	96	—	434
Assets transferred to right-of-use assets on implementation of IFRS 16 (Note 19)	—	(3)	—	—	(3)
Amortization	8	31	11	—	50
Disposals (Note 4(R))	(9)	(1)	—	—	(10)
Change in foreign exchange rates	—	(1)	—	—	(1)
Transfers	1	(1)	—	—	—
As at Dec. 31, 2019	117	246	107	—	470
Amortization	**8**	**28**	**15**	**—**	**51**
Disposals	**—**	**(1)**	**—**	**—**	**(1)**
Transfers	**—**	**(1)**	**1**	**—**	**—**
As at Dec. 31, 2020	**125**	**272**	**123**	**—**	**520**
Carrying amount					
As at Dec. 31, 2018	68	118	141	46	373
As at Dec. 31, 2019	32	132	143	11	318
As at Dec. 31, 2020	**24**	**140**	**146**	**3**	**313**

21. Goodwill

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

As at Dec. 31	2020	2019
Hydro	**258**	258
Wind and Solar	**175**	176
Energy Marketing	**30**	30
Total goodwill	**463**	464

For the purposes of the 2020 annual goodwill impairment review, the Corporation determined the recoverable amounts of the Wind and Solar segment by calculating the fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts for the period extending to the last planned asset retirement in 2073. The resulting fair value measurement is categorized within Level III of the fair value hierarchy. No impairment of goodwill arose for any segment. In 2020, the Corporation relied on the recoverable amounts determined in 2019 for the Hydro and Energy Marketing segments in performing the 2020 annual goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumptions impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility's useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2020 models ranged between $6 to $160 per MWh during the forecast period (2019 – $5 to $183 per MWh). Discount rates used for the goodwill impairment calculation in 2020 ranged from 4.8 per cent to 6.3 per cent (2019 – 3.6 per cent to 7.0 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

22. Other Assets

The components of other assets are as follows:

As at Dec. 31	2020	2019
South Hedland prepaid transmission access and distribution costs	**70**	67
Deferred licence fees	**—**	9
Project development costs	**25**	19
Long-term prepaids and other assets	**59**	56
Loan receivable	**52**	47
Total other assets	**206**	198

South Hedland prepaid transmission access and distribution costs are costs that are amortized on a straight-line basis over the South Hedland PPA contract life.

Deferred licence fees consist primarily of licences to lease the land on which certain generating assets are located, and are amortized on a straight-line basis over the useful life of the generating assets to which the licences relate.

Project development costs primarily include the project costs for US wind development projects (Note 4(F)) and an Alberta Hydro development project. Some projects were written off in 2019 and 2018 as they are no longer proceeding (see Note 7(D)).

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

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $52 million (2019 – $47 million) (net) of the Kent Hills Wind bond financing proceeds to its 17 per cent partner. The loan bears interest at 4.55 per cent, with interest payable quarterly, commencing on Dec. 31, 2017, is unsecured and matures on Oct. 2, 2022.

23. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2018	407	49	456
IFRS 16 transition adjustment	—	(2)	(2)
Liabilities incurred	7	7	14
Liabilities settled	(34)	(9)	(43)
Accretion	23	—	23
Acquisition of liabilities	16	3	19
Disposition of liabilities	(23)	(9)	(32)
Revisions in estimated cash flows(1)	96	7	103
Revisions in discount rates(1)	16	—	16
Reversals	—	(1)	(1)
Change in foreign exchange rates	(7)	—	(7)
Balance, Dec. 31, 2019	501	45	546
Liabilities incurred	**1**	**34**	**35**
Liabilities settled	**(18)**	**(19)**	**(37)**
Accretion	**30**	**—**	**30**
Acquisition of liabilities	**1**	**—**	**1**
Revisions in estimated cash flows(2)	**61**	**11**	**72**
Revisions in discount rates(3)	**36**	**—**	**36**
Reversals	**—**	**(6)**	**(6)**
Change in foreign exchange rates	**(4)**	**—**	**(4)**
Balance, Dec. 31, 2020	**608**	**65**	**673**

(1) During 2019, the Corporation adjusted the Centralia mine decommissioning and restoration provision as management no longer believes that the fine coal recovery and reclamation work will occur as originally proposed. Refer to Note 3(A)(III) for further details. In addition, due to the changes in estimated useful lives, the discount rates used for the Alberta Thermal and mining operations decommissioning provisions were changed. The use of a lower inflation rate decreased the corresponding liabilities.

(2) During 2020, the Corporation adjusted the Highvale mine decommissioning and restoration provision to reflect the mine closure advancement, an updated mine plan and current mining activity including increased volume of material movement. Refer to Note 3(A)(III) for further details. This increase was partially offset by a decrease in the Sarnia decommissioning and restoration provision as a result of an updated engineering study.

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2019	501	45	546
Current portion	36	22	58
Non-current portion	465	23	488
Balance, Dec. 31, 2020	**608**	**65**	**673**
Current portion	**21**	**38**	**59**
Non-current portion	**587**	**27**	**614**

A. Decommissioning and Restoration

A provision has been recognized for all generating facilities and mines for which TransAlta is legally, or constructively, required to remove the facilities at the end of their useful lives and restore the sites to their original condition. TransAlta estimates that the undiscounted amount of cash flow required to settle these obligations is approximately $1.4 billion, which will be incurred between 2021 and 2073. The majority of the costs will be incurred between 2025 and 2050. At Dec. 31, 2020, the Corporation had provided a surety bond in the amount of US$147 million (2019 – US$147 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2020, the Corporation had provided letters of credit in the amount of $131 million (2019 – $128 million) in support of future decommissioning obligations at the Alberta Highvale mine.

B. Other Provisions

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

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

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

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	2020			2019		
	Carrying value	**Face value**	**Interest**[1]	Carrying value	Face value	Interest[1]
Credit facilities[2]	**114**	**114**	**2.7%**	220	220	3.5%
Debentures	**249**	**251**	**7.1%**	647	651	5.8%
Senior notes[3]	**886**	**894**	**5.4%**	905	914	5.4%
Non-recourse[4]	**1,837**	**1,858**	**4.1%**	1,144	1,157	4.3%
Other[5]	**141**	**147**	**7.1%**	154	162	7.1%
	3,227	**3,264**		3,070	3,104	
Lease liabilities	**134**			142		
	3,361			3,212		
Less: current portion of long-term debt	**(97)**			(494)		
Less: current portion of lease liabilities	**(8)**			(19)		
Total current long-term debt and lease liabilities	**(105)**			(513)		
Total credit facilities, long-term debt and lease liabilities	**3,256**			2,699		

(1) Interest is an average rate weighted by principal amounts outstanding before the effect of hedging.
(2) Composed of bankers' acceptances and other commercial borrowings under long-term committed credit facilities.
(3) US face value at Dec. 31, 2020 — US$700 million (Dec. 31, 2019 — US$700 million).
(4) Includes AU$800 million TEC offering.
(5) Includes US$110 million at Dec. 31, 2020 (Dec. 31, 2019 — US$117 million) of tax equity financing.

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

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

(1) TransAlta has obligations to issue letters of credit and cash collateral to secure potential liabilities to certain parties, including those related to potential environmental obligations, commodity risk management and hedging activities, pension plan obligations, construction projects and purchase obligations. At Dec. 31, 2020, we provided cash collateral of $49 million.
(2) TransAlta has letters of credit of $89 million and TransAlta Renewables has letters of credit of $92 million issued from uncommitted demand facilities; these obligations are backstopped and reduce the available capacity on the committed credit facilities.
(3) One of the bilateral $80 million credit facilities has a maturity date of Q2 2021;the remaining two bilateral credit facilities has a maturity date of Q2, 2022.

The $1.95 billion (Dec. 31, 2019 – $1.95 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected – Canadian prime, bankers' acceptances, US LIBOR or US base rate – in accordance with a pricing grid that is standard for such facilities.

In 2019, the Corporation renewed these credit facilities and TransAlta Renewables' facility was increased by $200 million to $700 million.

The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $1.5 billion available under the credit facilities, the Corporation also has $703 million of available cash and cash equivalents and $17 million ($11 million principal portion) in cash restricted for repayment of the OCP bonds (refer to section E below).

Debentures bear interest at fixed rates ranging from 6.9 per cent to 7.3 per cent and have maturity dates ranging from 2029 to 2030.

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

On Aug. 2, 2018, the Corporation early redeemed all of its outstanding 6.40 per cent debentures, which were due Nov. 18, 2019, for the principal amount of $400 million. The redemption price was $425 million in aggregate, including a $19 million prepayment premium recognized in net interest expense and $6 million in accrued and unpaid interest to the redemption date.

Senior notes bear interest at rates ranging from 4.5 per cent to 6.5 per cent and have maturity dates ranging from 2022 to 2040.

During 2018, the Corporation early redeemed its outstanding 6.650 per cent US$500 million senior notes due May 15, 2018. The repayment was hedged with foreign exchange forwards and cross-currency swaps. The redemption price for the notes was approximately $617 million (US$516 million), including a $5 million early redemption premium, recognized in net interest expense, and $14 million in accrued and unpaid interest to the redemption date.

A total of US$370 million (2019 — US$370 million) of the senior notes has been designated as a hedge of the Corporation's net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2042 and bear interest at rates ranging from 2.95 per cent to 4.51 per cent.

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

During 2018, the Corporation:
- Paid out the US$25 million non-recourse debt related to its Mass Solar projects.
- Monetized the OCA and closed a $345 million bond offering through its indirect wholly owned subsidiary TransAlta OCP by way of private placement. The non-recourse amortizing bonds bear interest from their date of issuance at a rate of 4.509 per cent per annum, payable semi-annually and maturing on Aug. 5, 2030.

Other consists of an unsecured commercial loan obligation that bears interest at 5.9 per cent and matures in 2023, requiring annual payments of interest and principal, and tax equity financings related to Big Level and Antrim of $112 million (2019 – $122 million) and Lakeswind of $22 million (2019 – $23 million).

During 2019, coinciding with Antrim and Big Level each achieving commercial operation, TransAlta received tax equity funding of approximately US$41 million and US$85 million, respectively. Refer to Note 4(T) for further details.

Tax equity financings are typically represented by the initial equity investments made by the project investors at each project (net of financing costs incurred), except for the Lakeswind acquired tax equity which was initially recognized at its fair value. Tax equity financing balances are reduced by the value of tax benefits (production tax credits and tax depreciation) allocated to the investor and by cash distributions paid to the investor for their share of net earnings and cash flow generated at each project. Tax equity financing balances are increased by interest recognized at the implicit interest rate. In 2019, the Big Level and Antrim projects claimed accelerated (bonus) tax depreciation of $35 million in total, which was allocated to the tax equity investor, and had the effect of reducing the tax equity financing balance. The maturity dates of each financing are subject to change and primarily dependent upon when the project investor achieves the agreed upon targeted rate of return. The Corporation anticipates the maturity dates of the tax equity financings will be: Big Level and Antrim - in December 2029, 10 years from commercial operation of the projects; and Lakeswind - March 31, 2029.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2020, the Corporation was in compliance with all debt covenants.

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

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP, TEC Hedland and TransAlta OCP non-recourse bonds with a carrying value of $1.8 billion as at Dec. 31, 2020 (Dec. 31, 2019 - $1.1 billion) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the third quarter of 2020. However, funds in these entities that have accumulated since the third quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2021. At Dec. 31, 2020, $73 million (Dec. 31, 2019 –$42 million) of cash was subject to these financial restrictions.

Proceeds received from the TEC Notes in the amount of AU$7 million are not able to be accessed by other Corporate entities as the funds must be solely used by the project entities for the purpose of paying major maintenance costs.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit.

C. Security

Non-recourse debts totalling $1,441 million as at Dec. 31, 2020 (Dec. 31, 2019 – $719 million) are each secured by a first ranking charge over all of the respective assets of the Corporation's subsidiaries that issued the bonds, which include PPE with total carrying amounts of $1,277 million at Dec. 31, 2020 (Dec. 31, 2019 – $967 million) and intangible assets with total carrying amounts of $88 million (Dec. 31, 2019 – $63 million). At Dec. 31, 2020, a non-recourse bond of approximately $111 million (Dec. 31, 2019 – $119 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The TransAlta OCP bonds have a carrying value of $285 million (Dec. 31, 2019 – $305 million) and are secured by the assets of TransAlta OCP, including the right to annual capital contributions and OCA payments from the Government of Alberta. Under the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million (approximately $37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030.

D. Principal Repayments

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Principal repayments(1)	96	626	277	119	136	2,010	3,264
Lease liabilities(2)	(5)	6	5	5	5	118	134

(1) Excludes impact of hedge accounting and derivatives.
(2) Lease liabilities include a lease incentive of $13 million, expected to be received in 2021.

E. Restricted Cash

At Dec. 31, 2020, the Corporation had $9 million (Dec. 31, 2019 – $15 million) in restricted cash related to the Big Level tax equity financing that is held in a construction reserve account. The proceeds will be released from the construction reserve account upon certain conditions being met, which are expected to be finalized in 2021.

The Corporation had $17 million (Dec. 31, 2019 – $17 million) of restricted cash related to the TransAlta OCP bonds, which is required to be held in a debt service reserve account to fund the next scheduled debt repayment in February 2021.

The Corporation also had $45 million (Dec. 31, 2019 – nil) of restricted cash related to the TEC Notes; reserves are required to be held under TEC commercial arrangements and for debt service. Cash reserves may be replaced by letters of credit in the future.

F. Letters of Credit

Letters of credit issued by TransAlta are drawn on its committed syndicated credit facility, its $240 million bilateral committed credit facilities and its two uncommitted $100 million demand letters of credit facilities. Letters of credit issued by TransAlta Renewables are drawn on its uncommitted $100 million demand letter of credit facility.

Letters of credit are issued to counterparties under various contractual arrangements with the Corporation and certain subsidiaries of the Corporation. If the Corporation or its subsidiary does not perform under such contracts, the counterparty may present its claim for payment to the financial institution through which the letter of credit was issued. Any amounts owed by the Corporation or its subsidiaries under these contracts are reflected in the Consolidated Statements of Financial Position. All letters of credit expire within one year and are expected to be renewed, as needed, in the normal course of business. The total outstanding letters of credit as at Dec. 31, 2020, was $621 million (2019 – $690 million) with no (2019 – nil) amounts exercised by third parties under these arrangements.

25. Exchangeable Securities

On March 22, 2019, the Corporation entered into an Investment Agreement whereby Brookfield agreed to invest $750 million in TransAlta through the purchase of exchangeable securities, which are exchangeable into an equity ownership interest in TransAlta's Alberta Hydro Assets in the future at a value based on a multiple of the Alberta Hydro Assets' future-adjusted EBITDA ("Option to Exchange"). On May 1, 2019, Brookfield invested the initial tranche of $350 million in exchange for seven per cent unsecured subordinated debentures due May 1, 2039. On Oct. 30, 2020, Brookfield invested the second tranche of $400 million in exchange for redeemable, retractable first preferred shares.

A. $750 million Exchangeable Securities

As at	Dec. 31, 2020			Dec. 31, 2019		
	Carrying value	Face value	Interest	Carrying value	Face value	Interest
Exchangeable debentures – due May 1, 2039	**330**	**350**	**7 %**	326	350	7 %
Exchangeable preferred shares[1]	**400**	**400**	**7 %**	–	–	7 %
Total long term debt	**730**	**750**		**326**	**350**	

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

If Brookfield chooses not to exercise its Option to Exchange as outlined below, TransAlta has the right after Dec. 31, 2028 to redeem for cash all or any portion of the Exchangeable Securities for the original subscription price, plus any accrued but unpaid interest or dividends payable, provided the minimum proceeds to Brookfield for each redemption (other than the final redemption) is not less than $100 million and provided all Exchangeable Securities must be redeemed within 36 months of the first optional redemption.

B. Option to Exchange

As at	Dec. 31, 2020		Dec. 31, 2019	
Description	Base fair value	Sensitivity	Base fair value	Sensitivity
Option to exchange – embedded derivative	**–**	**nil -33**	–	nil -27

The Investment Agreement allows Brookfield the Option to Exchange all of the outstanding exchangeable securities into an equity ownership interest of up to a maximum 49 per cent in an entity formed to hold TransAlta's Alberta Hydro Assets after Dec. 31, 2024. The fair value of the Option to Exchange is considered a Level III fair value measurement as there is no available market-observable data. It is therefore valued using a mark-to-forecast model with inputs that are based on historical data and changes in underlying discount rates only when it represents a long-term change in the value of the Option to Exchange.

Sensitivity ranges for the base fair value are determined using reasonably possible alternative assumptions for key unobservable inputs, which is mainly the change in the implied discount rate of the future cash flow. The sensitivity analysis has been prepared using the Corporation's assessment that a change in the implied discount rate of the future cash flow of 1 per cent is a reasonably possible change.

The maximum equity interest Brookfield can own with respect to the Hydro Assets is 49 per cent. If Brookfield's ownership interest is less than 49 per cent at conversion, Brookfield has a one-time option payable in cash to increase its ownership to up to 49 per cent, exercisable up until Dec. 31, 2028, and provided Brookfield holds at least 8.5 per cent of TransAlta's common shares. Under this top-up option, Brookfield will be able to acquire an additional 10 per cent interest in the entity holding the Hydro Assets, provided the 20-day volume-weighted average price ("VWAP") of TransAlta's common shares is not less than $14 per share prior to the exercise of the option, and up to the full 49 per cent if the 20-day VWAP of TransAlta's common shares at that time is not less than $17 per share. To the extent the value of the Investment would exceed a 49 equity interest, Brookfield will be entitled to receive the balance of the redemption price in cash.

26. Defined Benefit Obligation and Other Long-Term Liabilities

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

As at Dec. 31	2020	2019
Defined benefit obligation (Note 31)	**282**	268
Long-term incentive accruals (Note 30)	**4**	4
Other	**12**	29
Total	**298**	301

27. Common Shares

A. Issued and Outstanding

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

As at Dec. 31	2020		2019	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**277.0**	**2,978**	284.6	3,059
Purchased and cancelled under the NCIB	**(7.3)**	**(79)**	(7.7)	(83)
Effects of share-based payment plans	**—**	**(3)**	—	—
Stock options exercised	**0.1**	**—**	0.1	2
Issued and outstanding, end of year	**269.8**	**2,896**	277.0	2,978

B. NCIB Program

Shares purchased by the Corporation under the NCIB are recognized as a reduction to share capital equal to the average carrying value of the common shares. Any difference between the aggregate purchase price and the average carrying value of the common shares is recorded in deficit.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year:

For the year ended Dec. 31	2020	2019
Total shares purchased[(1)]	**7,352,600**	7,716,300
Average purchase price per share	**$ 8.33**	$ 8.80
Total cost	**61**	68
Weighted average book value of shares cancelled	**79**	83
Amount recorded in deficit	**18**	15

(1) As at Dec. 31, 2020, includes 456,200 (2019 -189,900) shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which was amended and restated on April 26, 2019, to reflect current market practice and to reflect changes to the take-over bid regime. As required, the Shareholder Rights Plan must be put before the Corporation's shareholders every three years for approval, and it was last approved on April 26, 2019. The primary objective of the Shareholder Rights Plan is to encourage a potential acquirer to meet certain minimum standards designed to promote the fair and equal treatment of all common shareholders. When an acquiring shareholder acquires 20 per cent or more of the Corporation's common shares, except in limited circumstances including by way of a “permitted bid” or a "competing permitted bid" (as defined in the Shareholder Rights Plan), the rights granted under the Shareholder Rights Plan become exercisable by all shareholders except those held by the acquiring shareholder. Each right will entitle a shareholder, other than the acquiring shareholder, to purchase additional common shares at a significant discount to market, thus exposing the person acquiring 20 per cent or more of the shares to substantial dilution of their holdings.

D. Earnings per Share

Year ended Dec. 31	2020	2019	2018
Net earnings (loss) attributable to common shareholders	**(336)**	52	(248)
Basic and diluted weighted average number of common shares outstanding (millions)	**275**	283	287
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(1.22)**	0.18	(0.86)

E. Dividends

On Dec. 23, 2020, the Corporation declared a quarterly dividend of $0.0450 per common share, payable on April 1, 2021. On Nov. 3, 2020, the Corporation declared a quarterly dividend of $0.0425 per common share, payable on Jan. 1, 2021.

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

28. Preferred Shares

A. Issued and Outstanding

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

As at Dec. 31	2020		2019	
Series	Number of shares *(millions)*	Amount	Number of shares *(millions)*	Amount
Series A	**10.2**	**248**	10.2	248
Series B	**1.8**	**45**	1.8	45
Series C	**11.0**	**269**	11.0	269
Series E	**9.0**	**219**	9.0	219
Series G	**6.6**	**161**	6.6	161
Issued and outstanding, end of year	**38.6**	**942**	38.6	942

I. Series G Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Aug. 30, 2019, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2019, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series G (the "Series G Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series H (the "Series H Shares"), there were 140,730 Series G Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series H Shares. Therefore, none of the Series G Shares were converted into Series H Shares on Sept. 30, 2019. As a result, the Series G Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series G Shares for the five-year period from and including Sept. 30, 2019, to, but excluding, Sept. 30, 2024, will be 4.988 per cent, which is equal to the five-year Government of Canada bond yield of 1.188 per cent, determined as of Aug. 30, 2019, plus 3.80 per cent, in accordance with the terms of the Series G Shares.

II. Series E Cumulative Redeemable Rate Reset Preferred Shares Conversion

On Sept. 17, 2017, the Corporation announced that, after taking into account all election notices received by the Sept. 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series E (the "Series E Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series F (the "Series F Shares"), there were 133,969 Series E Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series F Shares. Therefore, none of the Series E Shares were converted into Series F Shares on Sept. 30, 2017. As a result, the Series E Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series E Shares for the five-year period from and including Sept. 30, 2017, to, but excluding, Sept. 30, 2022, will be 5.194 per cent, which is equal to the five-year Government of Canada bond yield of 1.544 per cent, determined as of Aug. 31, 2017, plus 3.65 per cent, in accordance with the terms of the Series E Shares.

III. Series C Cumulative Redeemable Rate Reset Preferred Shares Conversion

On June 16, 2017, the Corporation announced that, after taking into account all election notices received by the June 15, 2017, deadline for the conversion of the Cumulative Redeemable Rate Reset Preferred Shares, Series C (the "Series C Shares") into Cumulative Redeemable Floating Rate Preferred Shares Series D (the "Series D Shares"), there were 827,628 Series C Shares tendered for conversion, which was less than the one million shares required to give effect to conversions into Series D Shares. Therefore, none of the Series C Shares were converted into Series D Shares on June 30, 2017. As a result, the Series C Shares will be entitled to receive quarterly fixed cumulative preferential cash dividends, if, as and when declared by the Board. The annual dividend rate for the Series C Shares for the five-year period from and including June 30, 2017, to, but excluding, June 30, 2022, will be 4.027 per cent, which is equal to the five-year Government of Canada bond yield of 0.927 per cent, determined as of May 31, 2017, plus 3.10 per cent, in accordance with the terms of the Series C Shares.

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

On March 17, 2016, the Corporation announced that 1,824,620 of its 12.0 million Series A Cumulative Fixed Redeemable Rate Reset Preferred Shares ("Series A Shares") were tendered for conversion, on a one-for-one basis, into Series B Cumulative Redeemable Floating Rate Preferred Shares ("Series B Shares") after having taken into account all election notices. As a result of the conversion, the Corporation had 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2020.

The Series A Shares pay fixed cumulative preferential cash dividends on a quarterly basis for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on an annual fixed dividend rate of 2.709 per cent.

The Series B Shares pay quarterly floating rate cumulative preferential cash dividends for the five-year period from and including March 31, 2016, to, but excluding, March 31, 2021, if, as and when declared by the Board based on the 90-day Treasury Bill rate plus 2.03 per cent.

On March 1, 2021, the Corporation announced that it does not intend to exercise its right to redeem all or any part of the currently outstanding Series A Shares and Series B Shares. The Corporation has provided a notice to the registered shareholders of Series A Shares of the conversion right, on a one-for-one basis, into Series B Shares, and vice versa, providing Series B shareholders the right to exchange Series B Shares, on a one-for-one basis, into Series A Shares. Series A shareholders may elect to retain any or all of their current share holdings and continue to receive a fixed rate quarterly dividend. Series B shareholder may also elect to retain any or all of their current share holdings and continue to receive a floating rate quarterly dividend. After exercising conversion rights, if the balance that remains for either

Series A Shares or Series B Shares is less than 1 million, that remaining balance of will automatically convert to the other Series. Shareholders' notice of intention to convert must be received by the transfer agent no later than March 16, 2021 and the conversion date will be effective March 31, 2021. The annual dividend rate for the Series A Shares for the five-year period from and including March 31, 2021, to, but excluding, March 31, 2026, will be 2.877 per cent, which is equal to the five-year Government of Canada Bond yield of 0.847 per cent, determined as of March 1, 2021, plus 2.03 per cent. The annual dividend rate for the Series B Shares for the three month floating rate period from and including March 31, 2021, to, but excluding, June 30, 2021, will be 2.103 per cent based on the most recent auction of 90-day Government of Canada Treasury Bills of 0.073 per cent plus 2.03 per cent. The Floating Quarterly Dividend Rate will be reset every quarter.

V. Preferred Share Series Information

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

- Redeemable at the option of the Corporation, in whole or in part, for $25.00 per share, plus all declared and unpaid dividends at the time of redemption.
- Convertible at the holder's option into a specified series of non-voting cumulative redeemable floating rate first preferred shares that pay cumulative floating rate quarterly cash dividends, as approved by the Board, based on the sum of the then Government of Canada 90-day Treasury Bill rate (the floating rate "Benchmark") plus a specified spread. The cumulative floating rate first preferred shares are also redeemable at the option of the Corporation and convertible back into each original cumulative fixed rate first preferred share series, at each subsequent Rate Reset Date, on the same terms as noted above.

Characteristics specific to each first preferred share series as at Dec. 31, 2020, are as follows:

Series	Rate during term	Annual dividend rate per share (*$*)	Next conversion date	Rate spread over Benchmark (*per cent*)	Convertible to Series
A	Fixed	0.67724	March 31, 2021	2.03	B
B	Floating	0.73801	March 31, 2021	2.03	A
C	Fixed	1.00676	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29852	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.24700	Sept. 30, 2024	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the value of the preferred share dividends declared in 2020, 2019 and 2018:

	Total dividends declared		
Series	**2020**	2019(1)	2018
A	**9**	5	9
B(2)	**1**	1	1
C	**14**	8	14
E	**15**	9	15
G	**10**	7	11
Total for the year	**49**	30	50

(1) No dividends were declared in the first quarter of 2019 as the quarterly dividend related to the period covering the first quarter of 2019 was declared in December 2018.

(2) Series B Preferred Shares pay quarterly dividends at a floating rate based on the 90-day Government of Canada Treasury Bill rate, plus 2.03 per cent.

On Dec. 23, 2020, the Corporation declared a quarterly dividend of $0.16931 per share on the Series A preferred shares, $0.13186 per share on the Series B preferred shares, $0.25169 per share on the Series C preferred shares, $0.32463 per share on the Series E preferred shares, and $0.31175 per share on the Series G preferred shares, all payable on March 31, 2021.

29. Accumulated Other Comprehensive Income

The components of, and changes in, accumulated other comprehensive income (loss) are as follows:

	2020	2019
Currency translation adjustment		
Opening balance, Jan. 1	**(21)**	17
Gains (losses) on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax	**(11)**	(59)
Gains (losses) on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax	**11**	21
Balance, Dec. 31	**(21)**	(21)
Cash flow hedges		
Opening balance, Jan. 1	**527**	508
Gains (losses) on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(1)	**(91)**	19
Balance, Dec. 31	**436**	527
Employee future benefits		
Opening balance, Jan. 1	**(55)**	(29)
Net actuarial gains (losses) on defined benefit plans, net of tax(2)	**(11)**	(26)
Balance, Dec. 31	**(66)**	(55)
Other		
Opening balance, Jan. 1	**3**	(15)
Change in ownership of TransAlta Renewables	**—**	1
Intercompany investments at FVOCI	**(50)**	17
Balance, Dec. 31	**(47)**	3
Accumulated other comprehensive income	**302**	454

(1) Net of income tax of $23 million for the year ended Dec. 31, 2020 (2019 — $6 million).

(2) Net of income tax of $3 million for the year ended Dec. 31, 2020 (2019 — $7 million).

30. Share-Based Payment Plans

The Corporation has the following share-based payment plans:

A. Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plan

Under the PSU and RSU Plan, grants may be made annually, but are measured and assessed over a three-year performance period. Grants are determined as a percentage of participants' base pay and are converted to PSUs or RSUs on the basis of the Corporation's common share price at the time of grant. Vesting of PSUs is subject to achievement over a three-year period of two to three performance measures that are established at the time of each grant. RSUs are subject to a three-year cliff-vesting requirement. RSUs and PSUs track the Corporation's share price over the three-year period and accrue dividends as additional units at the same rate as dividends paid on the Corporation's common shares.

During 2019, as a result of the Corporation's change in its intended settlement policy, the accounting classification of the RSUs and PSUs changed from cash-settled to equity-settled. The RSUs and PSUs have been accounted for as equity-settled grants from the dates of the policy change, with fair values determined as at that date. On average, the fair value of outstanding grants used in accounting for the change was $8.29, measured using the Black-Scholes option pricing model. As a result of this change, the liability for the cash-settled grants ($25 million) has been derecognized and the equity-settled fair value ($24 million) has been recognized in contributed surplus, with the net difference of $1 million representing the cumulative change in compensation expense. No changes were made to the vesting or performance conditions associated with the awards. The Human Resources Committee of the Board has the discretion to determine whether payments on settlement are made through purchase of shares on the open market or in cash. The expenses related to this plan are recognized during the period earned, with the corresponding amounts due under the plan recorded in contributed surplus (2018 – liabilities). Prior to this change, the liability was valued at the end of each reporting period using the closing price of the Corporation's common shares on the TSX.

The pre-tax compensation expense related to PSUs and RSUs in 2020 was $15 million (2019 – $19 million, 2018 – $8 million), which is included in operations, maintenance and administration expense in the Consolidated Statements of Earnings (Loss).

B. Deferred Share Unit ("DSU") Plan

Under the DSU Plan, members of the Board and executives may, at their option, purchase DSUs using certain components of their fees or pay. A DSU is a notional share that has the same value as one common share of the Corporation and fluctuates based on the changes in the value of the Corporation's common shares in the marketplace. DSUs accrue dividends as additional DSUs at the same rate as dividends are paid on the Corporation's common shares. DSUs are redeemable in cash and may not be redeemed until the termination or retirement of the director or executive from the Corporation.

The Corporation accrues a liability and expense for the appreciation in the common share value in excess of the DSU's purchase price and for dividend equivalents earned. The pre-tax compensation expense related to the DSUs was $1 million in 2020 (2019 – $2 million, 2018 – nil).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 16.5 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In 2020, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with a weighted average exercise price of $9.17 that vest after a three-year period and expire seven years after issuance (2019 – 1.4 million stock options at $5.65; 2018 – 0.7 million stock options at $7.45). The expense recognized relating to these grants during 2020 was approximately $2 million (2019 – approximately $1 million, 2018 – approximately $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2020, are outlined below:

	Options outstanding		
Range of exercise prices[1] *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 10.00	**4.0**	**4.2**	**6.85**

(1) Options currently exercisable as at Dec. 31, 2020.

31. Employee Future Benefits

A. Description

The Corporation sponsors registered pension plans in Canada and the US covering substantially all employees of the Corporation in these countries and specific named employees working internationally. These plans have defined benefit and defined contribution options, and in Canada there is an additional non-registered supplemental plan for eligible employees whose annual earnings exceed the Canadian income tax limit. Except for the Highvale pension plan acquired in 2013, the Canadian and US defined benefit pension plans are closed to new entrants. The US defined benefit pension plan was frozen effective Dec. 31, 2010, resulting in no future benefits being earned. The supplemental pension plan was closed as of Dec. 31, 2015, and a new defined contribution supplemental pension plan commenced for executive members effective Jan. 1, 2016. Current executives as of Dec. 31, 2015, were grandfathered into the old supplemental plan.

The latest actuarial valuation for accounting purposes of the US pension plan was at Jan. 1, 2020. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2019. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2020.

Funding of the registered pension plans complies with applicable regulations that require actuarial valuations of the pension funds at least once every three years in Canada, or more, depending on funding status, and every year in the US. The supplemental pension plan is solely the obligation of the Corporation. The Corporation is not obligated to fund the supplemental plan but is obligated to pay benefits under the terms of the plan as they come due. The Corporation posted a letter of credit in March 2020 for the amount of $89 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2019, and Jan. 1, 2020, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2020.

The Corporation provides several defined contribution plans, including an Australian superannuation plan and a US 401(k) savings plan, that provide for company contributions from 5 per cent to 10 per cent, depending on the plan. Optional employee contributions are allowed for all the defined contribution plans.

B. Costs Recognized

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

Year ended Dec. 31, 2020	**Registered**	**Supplemental**	**Other**	**Total**
Current service cost	**5**	**2**	**1**	**8**
Administration expenses	**1**	**—**	**—**	**1**
Interest cost on defined benefit obligation	**16**	**3**	**1**	**20**
Interest on plan assets	**(11)**	**(1)**	**—**	**(12)**
Curtailment and amendment gain	**(2)**	**—**	**—**	**(2)**
Defined benefit expense	**9**	**4**	**2**	**15**
Defined contribution expense	**9**	**—**	**—**	**9**
Net expense	**18**	**4**	**2**	**24**

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

Year ended Dec. 31, 2018	Registered	Supplemental	Other	Total
Current service cost	9	2	1	12
Administration expenses	1	—	—	1
Interest cost on defined benefit obligation	18	3	1	22
Interest on plan assets	(13)	—	—	(13)
Defined benefit expense	15	5	2	22
Defined contribution expense	10	—	—	10
Net expense	25	5	2	32

C. Status of Plans

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

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

Year ended Dec. 31, 2019	Registered	Supplemental	Other	Total
Fair value of plan assets	373	13	–	386
Present value of defined benefit obligation	(543)	(99)	(22)	(664)
Funded status – plan deficit	(170)	(86)	(22)	(278)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(3)	(5)	(2)	(10)
Other long-term liabilities	(167)	(81)	(20)	(268)
Total amount recognized	(170)	(86)	(22)	(278)

D. Plan Assets

The fair value of the plan assets of the defined benefit pension and other post-employment benefit plans is as follows:

	Registered	**Supplemental**	**Other**	**Total**
As at Dec. 31, 2018	368	13	–	381
Interest on plan assets	12	1	–	13
Net return on plan assets	40	–	–	40
Contributions	6	4	1	11
Benefits paid	(50)	(5)	(1)	(56)
Administration expenses	(2)	–	–	(2)
Effect of translation on US plans	(1)	–	–	(1)
As at Dec. 31, 2019	373	13	–	386
Interest on plan assets	**11**	**1**	**–**	**12**
Net return on plan assets	**25**	**(1)**	**–**	**24**
Contributions	**6**	**6**	**1**	**13**
Benefits paid	**(45)**	**(5)**	**(1)**	**(51)**
Administration expenses	**(1)**	**–**	**–**	**(1)**
Effect of translation on US plans	**(2)**	**–**	**–**	**(2)**
As at Dec. 31, 2020	**367**	**14**	**–**	**381**

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

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

Year ended Dec. 31, 2019	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	66	—	66
US	—	28	—	28
International	—	102	—	102
Private	—	—	1	1
Bonds				
AAA	—	40	—	40
AA	—	68	—	68
A	—	37	—	37
BBB	1	21	—	22
Below BBB	—	3	—	3
Money market and cash and cash equivalents	—	19	—	19
Total	1	384	1	386

Plan assets do not include any common shares of the Corporation at Dec. 31, 2020 and Dec. 31, 2019. The Corporation charged the registered plan nil for administrative services provided for the year ended Dec. 31, 2020 (2019 – nil).

E. Defined Benefit Obligation

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

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2018	514	80	25	619
Current service cost	7	2	1	10
Interest cost	19	3	1	23
Benefits paid	(51)	(4)	(1)	(56)
Curtailment	(3)	–	–	(3)
Actuarial gain arising from demographic assumptions	–	–	(2)	(2)
Actuarial loss arising from financial assumptions	57	9	2	68
Actuarial gain (loss) arising from experience adjustments	2	9	(4)	7
Effect of translation on US plans	(2)	–	–	(2)
Present value of defined benefit obligation as at Dec. 31, 2019	543	99	22	664
Current service cost	**5**	**2**	**1**	**8**
Interest cost	**16**	**3**	**1**	**20**
Benefits paid	**(45)**	**(5)**	**(1)**	**(51)**
Curtailment	**(2)**	**–**	**–**	**(2)**
Actuarial loss arising from demographic assumptions	**–**	**–**	**–**	**–**
Actuarial loss arising from financial assumptions	**43**	**10**	**2**	**55**
Actuarial gain arising from experience adjustments	**(17)**	**–**	**–**	**(17)**
Effect of translation on US plans	**(1)**	**–**	**(1)**	**(2)**
Present value of defined benefit obligation as at Dec. 31, 2020	**542**	**109**	**24**	**675**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2020 is 14.4 years.

F. Contributions

The expected employer contributions for 2021 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**5**	**2**	**12**

G. Assumptions

The significant actuarial assumptions used in measuring the Corporation's defined benefit obligation for the defined benefit pension and other post-employment benefit plans are as follows:

	As at Dec. 31, 2020			As at Dec. 31, 2019		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**2.4**	**2.3**	**2.3**	3.0	3.0	3.0
Rate of compensation increase	**2.9**	**3.0**	**—**	2.8	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(1)(3)	**—**	**—**	**6.8**	—	—	7.0
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.0**	**3.0**	**3.0**	3.9	3.8	3.9
Rate of compensation increase	**2.9**	**3.0**	**—**	2.5	3.0	—
Assumed health-care cost trend rate						
Health-care cost escalation(2)(4)	**—**	**—**	**7.1**	—	—	7.4
Dental-care cost escalation	**—**	**—**	**4.0**	—	—	4.0

(1) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(2) 2020 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2030 for Canada.
(3) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2030 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(4) 2019 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.

H. Sensitivity Analysis

The following table outlines the estimated increase in the net defined benefit obligation assuming certain changes in key assumptions:

	Canadian plans			**US plans**	
Year ended Dec. 31, 2020	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**74**	**17**	**2**	**3**	**1**
1% increase in the salary scale	**5**	**—**	**—**	**4**	**1**
1% increase in the health-care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**20**	**4**	**—**	**1**	**—**

32. Joint Arrangements

Joint arrangements at Dec. 31, 2020, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Alberta Thermal	50	Dual-fuel facility in Alberta, of which TA Cogen has a 50 per cent interest, operated by Heartland Generation Ltd., an affiliate of Energy Capital Partners
Pioneer Pipeline	Alberta Thermal	50	Natural gas pipeline in Alberta operated by TMI
Goldfields Power	Australian Gas	50	Gas-fired facility in Australia operated by TransAlta
Fort Saskatchewan	North American Gas	60	Cogeneration facility in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Australian Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind and Solar	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

Joint ventures	Segment	Ownership *(per cent)*	Description
Skookumchuck	Wind and Solar	49	Wind generation facility in Washington operated by Southern Power

33. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2020	2019	2018
(Use) source:			
Accounts receivable	**(79)**	261	58
Prepaid expenses	**2**	—	19
Income taxes receivable	**(4)**	(6)	—
Inventory	**6**	(13)	(21)
Accounts payable, accrued liabilities and provisions	**160**	(130)	(97)
Income taxes payable	**4**	9	(3)
Change in non-cash operating working capital	**89**	121	(44)

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2019	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2020
Long-term debt and lease obligations	3,212	**133**	**16**	**—**	**5**	**(5)**	**3,361**
Exchangeable securities	326	**400**	**—**	**—**	**—**	**4**	**730**
Dividends payable (common and preferred)	37	**(86)**	**—**	**107**	**—**	**1**	**59**
Total liabilities from financing activities	3,575	**447**	**16**	**107**	**5**	**—**	**4,150**

	Balance Dec. 31, 2018	Net cash flows	New leases	Tax shield on tax equity financing	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2019
Long-term debt and lease liabilities	3,267	(70)	133	(35)	—	(42)	(41)	3,212
Exchangeable securities	—	350	—	—	—	—	(24)	326
Dividends payable (common and preferred)	58	(85)	—	—	64	—	—	37
Total liabilities from financing activities	**3,325**	**195**	**133**	**(35)**	**64**	**(42)**	**(65)**	**3,575**

34. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	**2020**	2019	**Increase/ (decrease)**
Long-term debt(1)	**3,361**	3,212	**149**
Exchangeable securities	**730**	326	**404**
Equity			
Common shares	**2,896**	2,978	**(82)**
Preferred shares	**942**	942	**—**
Contributed surplus	**38**	42	**(4)**
Deficit	**(1,826)**	(1,455)	**(371)**
Accumulated other comprehensive income	**302**	454	**(152)**
Non-controlling interests	**1,084**	1,101	**(17)**
Less: available cash and cash equivalents(2)	**(703)**	(411)	**(292)**
Less: principal portion of restricted cash on TransAlta OCP bonds(3)	**(11)**	(10)	**(1)**
Less: fair value asset of hedging instruments on long-term debt(4)	**(2)**	(7)	**5**
Total capital	**6,811**	7,172	**(361)**

(1) Includes lease liabilities, amounts outstanding under credit facilities, tax equity liabilities and current portion of long-term debt.
(2) The Corporation includes available cash and cash equivalents as a reduction in the calculation of capital, as capital is managed internally and evaluated by management using a net debt position. In this regard, these funds may be available and used to facilitate repayment of debt.
(3) The Corporation includes the principal portion of restricted cash on TransAlta OCP bonds because this cash is restricted specifically to repay outstanding debt.
(4) The Corporation includes the fair value of economic and designated hedging instruments on debt in an asset, or liability, position as a reduction, or increase, in the calculation of capital, as the carrying value of the related debt has either increased, or decreased, due to changes in foreign exchange rates.

The Corporation's overall capital management strategy and its objectives in managing capital are as follows:

A. Maintain a Strong Financial Position

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain a strong financial position that enables the Corporation to access capital markets at reasonable interest rates.

Maintaining a strong balance sheet also allows its commercial team to contract the Corporation's portfolio with a variety of counterparties on terms and prices that are favourable to the Corporation's financial results and provides the Corporation with better access to capital markets through commodity and credit cycles. The Corporation has an investment-grade credit rating from DBRS (stable outlook). During 2020, Moody's reaffirmed its issuer rating of Ba1 with a stable outlook; DBRS reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low) and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BB+ with stable outlook. The Corporation remains focused on strengthening its financial position and cash flow coverage ratios. Credit ratings provide information relating to the Corporation's financing costs, liquidity and operations and affect the Corporation's ability to obtain short-term and long-term financing and/or the cost of such financing.

Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. The methodologies and ratios used by rating agencies to assess our credit rating are not publicly disclosed. We have developed our own definitions of ratios and targets to help evaluate the strength of our financial position. These metrics and ratios are not defined under IFRS and may not be comparable to those used by other entities or by rating agencies. These ratios are summarized in the table below:

As at Dec. 31	2020	2019	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.2**	4.5	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**18.3**	19.0	20 to 25
Adjusted net debt to adjusted comparable earnings before interest, taxes, depreciation and amortization (times)	**3.9**	3.9	3.0 to 3.5
Deconsolidated net debt to deconsolidated comparable EBITDA (times)	**4.6**	4.2	2.5 to 3.0

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO less the termination payments for the Sundance B and C PPAs plus interest on debt, exchangeable securities and lease liabilities (net of capitalized interest) divided by interest on debt, exchangeable securities and lease liabilities (net of capitalized interest) plus 50 per cent of dividends paid on preferred shares. The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less the termination payments for the Sundance B and C PPAs less 50 per cent of dividends paid on preferred shares divided by adjusted net debt (current and long-term debt plus exchangeable securities plus 50 per cent of outstanding preferred shares less available cash and cash equivalents less principal portion of TransAlta OCP restricted cash and including fair value assets of hedging instruments on debt). The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Adjusted Comparable EBITDA is calculated as adjusted net debt divided by adjusted comparable EBITDA. Adjusted comparable EBITDA is calculated as earnings before interest, taxes, depreciation and amortization and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing business operations as well as the termination payments for the Sundance B and C PPAs. The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

Deconsolidated net debt to deconsolidated comparable EBITDA is calculated as deconsolidated net debt (long-term debt, lease liabilities and exchangeable debentures including current portion and fair value (asset) liability of hedging instruments on debt plus 50 per cent issued preferred shares less cash and cash equivalents less principal portion of TransAlta OCP restricted cash less TransAlta Renewables long-term debt and lease liabilities including current portion less tax equity financing) divided by deconsolidated comparable EBITDA (comparable EBITDA less TransAlta Renewables comparable EBITDA less TA Cogen comparable EBITDA plus dividends received from TransAlta Renewables plus dividends received from TA Cogen). The exchangeable preferred shares (see Note 25) are considered equity with dividend payments for credit purposes. The Corporation's goal is to maintain this ratio in a range of 2.5 to 3.0 times.

At times, the credit ratios may be outside of the specified ranges while the Corporation executes its conversion to gas and growth strategy, but we remain focused on maintaining a strong balance sheet.

Management routinely monitors forecasted net earnings, cash flows, capital expenditures and scheduled repayment of debt with a goal of meeting the above ratio targets and to meet dividend and PP&E expenditure requirements.

B. Ensure Sufficient Cash and Credit is Available to Fund Operations, Pay Dividends, Distribute Payments to Subsidiaries' Non-Controlling Interests, Invest in PP&E and Make Acquisitions

For the years ended Dec. 31, 2020 and 2019, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2020	2019	Increase (decrease)
Cash flow from operating activities	**702**	849	**(147)**
Change in non-cash working capital	**(89)**	(121)	**32**
Cash flow from operations before changes in working capital	**613**	728	**(115)**
Dividends paid on common shares	**(47)**	(45)	**(2)**
Dividends paid on preferred shares	**(39)**	(40)	**1**
Distributions paid to subsidiaries' non-controlling interests	**(97)**	(106)	**9**
Property, plant and equipment expenditures	**(486)**	(417)	**(69)**
Inflow (outflow)	**(56)**	120	**(176)**

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2020, $1.5 billion (2019 – $1.3 billion) of the Corporation's credit facilities were fully available.

From time to time, TransAlta accesses capital markets, as required, to help fund some of these periodic net cash outflows, to maintain its available liquidity, and to maintain its capital structure and credit metrics within targeted ranges.

35. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2020, are as follows:

Subsidiary	Country	Ownership (per cent)	Principal activity
TransAlta Generation Partnership	Canada	100	Generation and sale of electricity
TransAlta Cogeneration, L.P.	Canada	50.01	Generation and sale of electricity
TransAlta Centralia Generation, LLC	US	100	Generation and sale of electricity
TransAlta Energy Marketing Corp.	Canada	100	Energy marketing
TransAlta Energy Marketing (U.S.), Inc.	US	100	Energy marketing
TransAlta Energy (Australia), Pty Ltd.	Australia	100	Generation and sale of electricity
TransAlta Renewables Inc.	Canada	60.1	Generation and sale of electricity

Associate or joint venture	Country	Ownership (per cent)	Principal activity
SP Skookumchuck Investment, LLC	US	49	Generation and sale of electricity
EMG International, LLC	US	30	Wastewater treatment and biogas fuel to generate electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed. Associates and joint ventures have been equity accounted for by the Corporation.

Transactions with Key Management Personnel

TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board. Key management personnel compensation is as follows:

Year ended Dec. 31	2020	2019	2018
Total compensation	**27**	30	17
Comprised of:			
Short-term employee benefits	**12**	13	11
Post-employment benefits	**2**	2	2
Termination benefits	**—**	2	—
Share-based payments	**13**	13	4

36. Commitments and Contingencies

In addition to commitments disclosed elsewhere in the financial statements, the Corporation has incurred the following additional contractual commitments, either directly or through its interests in joint operations. Approximate future payments under these agreements are as follows:

	2021	2022	2023	2024	2025	2026 and thereafter	Total
Natural gas, transportation and other contracts	141	149	137	134	134	1,353	**2,048**
Transmission	8	8	8	5	5	1	**35**
Coal supply and mining agreements	81	105	101	67	56	—	**410**
Long-term service agreements	31	37	22	18	10	55	**173**
Operating leases	4	2	2	1	1	26	**36**
Growth	509	411	93	—	—	—	**1,013**
TransAlta Energy Transition Bill	6	6	6	—	—	—	**18**
Total	**780**	**718**	**369**	**225**	**206**	**1,435**	**3,733**

A. Natural Gas, Transportation and Other Contracts

The Corporation has fixed price or volume natural gas purchase and transportation contracts. In addition to the commitments shown above, upon closing the sale of the Pioneer Pipeline, a 15-year transportation agreement will provide an additional 275 TJ per day of natural gas on a firm basis by 2023, bringing the total firm natural gas transportation contracts to 400 TJ per day by 2023. This agreement would replace the Corporation's existing 15-year commitment to purchase 139 TJ per day of natural gas on the Pioneer Pipeline, which remains in place until the closing of the Transaction. Other contracts relate to commitments for goods and services.

B. Transmission

The Corporation has several agreements to purchase transmission network capacity in the Pacific Northwest. Provided certain conditions for delivering the service are met, the Corporation is committed to the transmission at the supplier's tariff rate whether it is awarded immediately or delivered in the future after additional facilities are constructed.

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia thermal facility. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2025. In 2020, a new rail transportation service contract was entered into and pricing is reflective of current market conditions. As a result, there is an increase in expected rail transportation costs over the service period.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness joint operation and certain other mining royalty agreements. Some of these commitments have been reduced due to the accelerated plans to eliminate coal as a fuel source at the Sheerness facility by the end of 2021.

D. Long-Term Service Agreements

TransAlta has various service agreements in place, primarily for inspections and repairs and maintenance that may be required on natural gas facilities, coal facilities and turbines at various wind facilities.

E. Operating Leases

Includes lease commitments not recognized under IFRS 16 and lease commitments that have not yet commenced, mainly related to buildings, vehicles and land.

Prior to the adoption of IFRS 16, operating lease expenses were recognized as incurred in the statement of earnings. During the year ended Dec. 31, 2018, $8 million was recognized as an expense in respect of operating leases. Sublease payments received during 2020 were $2 million (2019 and 2018 – were less than $1 million). No contingent rental payments were made in respect of operating leases.

F. Growth

Commitments for growth relate to the following projects: conversion to gas and repowering Sundance Unit 5, Kaybob cogeneration project, Windrise project and any final costs associated with the Big Level and Antrim wind projects. Refer to Note 4 for further details on these projects.

G. TransAlta Energy Transition Bill Commitments

As part of the TransAlta Energy Transition Bill signed into law in the State of Washington and the subsequent MOA, we have committed to fund US$55 million in total over the remaining life of the Centralia coal plant to support economic and community development, promote energy efficiency and develop energy technologies related to the improvement of the environment. The MoA contains certain provisions for termination and in the event of the termination and certain circumstances, this funding or part thereof would no longer be required. As of Dec. 31, 2020, the Corporation has funded approximately US$41 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

A significant portion of the Corporation's electricity and thermal production are subject to PPAs and long-term contracts. The majority of these contracts include terms and conditions customary to the industry in which the Corporation operates. The nature of commitments related to these contracts includes: electricity and thermal capacity, availability and production targets; reliability and other plant-specific performance measures; specified payments for deliveries during peak and off-peak time periods; specified prices per MWh; risk sharing of fuel costs; and retention of heat rate risk.

I. Contingencies

TransAlta is occasionally named as a party in various claims and legal and regulatory proceedings that arise during the normal course of its business. TransAlta reviews each of these claims, including the nature of the claim, the amount in dispute or claimed, and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Corporation's favour or that such claims may not have a material adverse effect on TransAlta. Inquiries from regulatory bodies may also arise in the normal course of business, to which the Corporation responds as required.

I. Line Loss Rule Proceeding

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

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

II. FMG Disputes

The Corporation is currently engaged in a dispute with Fortescue Metals Group Ltd. ("FMG") as a result of FMG's purported termination of the South Hedland PPA. TransAlta sued FMG, seeking payments of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated. This matter has been rescheduled to proceed to trial beginning May 3, 2021, instead of June 15, 2020.

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

III. Mangrove Claim

On April 23, 2019, Mangrove commenced an action in the Ontario Superior Court of Justice, naming the Corporation, the incumbent members of the Board of Directors of the Corporation on such date and Brookfield BRP Holdings (Canada), as defendants. Mangrove is seeking to set aside the Brookfield Investment. TransAlta believes the claim is wholly lacking in merit and is taking all steps to defend against the allegations. This matter has been rescheduled and the three-week trial will begin on April 19, 2021.

IV. Keephills 1 Stator Force Majeure

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

V. Keephills 1 Superheater Force Majeure

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

VI. Sundance A Decommissioning

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

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

The Balancing Pool claims to be entitled to emissions performance credits ("EPCs"), valued at approximately $17 million per year, earned by the Hydro facilities under the *Carbon Competitiveness Incentive Regulation* from 2018-2020. Refer to Note 2(A) and 2(F)(IV) for the accounting policies on these credits. The dispute is based on the ownership of the EPCs as a result of a change in law provision under the Hydro PPA and that TransAlta is benefiting from the purported change in law. TransAlta has not received any benefit from the EPCs and has not recognized any benefit from the EPCs within its financial statements. TransAlta believes that the Balancing Pool has no rights to these credits. An arbitration has commenced and will be likely set down for a hearing sometime in early 2022.

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

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

37. Segment Disclosures

A. Description of Reportable Segments

The Corporation has eight reportable segments as described in Note 1.

The following tables provides each segment's results in the format that management organizes its segments to make operating decisions and assess performance. For internal reporting purpose, the earnings information from the Corporation's investment in Skookumchuck has been presented in the Wind and Solar segment on a proportionate basis. Information on a proportionate basis reflects the Corporation's share of Skookumchuck's statement of earnings on a line-by-line basis. Proportionate financial information is not, and is not intended to be, presented in accordance with IFRS. Under IFRS, the investment in Skookumchuck has been accounted for as a joint venture using the equity method. The table below also shows the reconciliation of the total segmented results to the statement of earnings reported under IFRS.

B. Reported Segment Earnings (Loss) and Segment Assets

I. Earnings Information

Year ended Dec. 31, 2020	Hydro	Wind and Solar[1]	North American Gas[2]	Australian Gas	Alberta Thermal[3]	Centralia[3]	Energy Marketing	Corporate	Total	Equity accounted investments[1]	IFRS Financials
Revenues	152	332	217	158	619	497	122	7	2,104	(3)	2,101
Fuel, carbon compliance and purchased power	8	25	66	10	573	279	—	7	968	—	968
Gross margin	144	307	151	148	46	218	122	—	1,136	(3)	1,133
Operations, maintenance and administration	37	53	49	32	131	60	30	80	472	—	472
Depreciation and amortization	28	136	46	43	270	105	2	25	655	(1)	654
Asset impairment	2	—	—	—	75	7	—	—	84	—	84
Taxes, other than income taxes	2	8	2	—	15	5	—	1	33	—	33
Net other operating expense (income)	—	—	—	—	(11)	—	—	—	(11)	—	(11)
Operating income (loss)	75	110	54	73	(434)	41	90	(106)	(97)	(2)	(99)
Equity income from associate[1]	—	—	—	—	—	—	—	—	—	1	1
Finance lease income	—	—	5	2	—	—	—	—	7	—	7
Net interest expense									(239)	1	(238)
Foreign exchange loss									17	—	17
Gain on sale of assets and other									9	—	9
Earnings before income taxes									(303)	—	(303)

(1) Skookumchuck has been included on a proportionate basis in the Wind and Solar segment.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(3) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

Year ended Dec. 31, 2019	Hydro	Wind and Solar	North American Gas[1]	Australian Gas	Alberta Thermal[2]	Centralia[2]	Energy Marketing	Corporate	Total
Revenues	156	312	209	160	816	571	129	(6)	2,347
Fuel, carbon compliance and purchased power	7	16	74	9	570	416	–	(6)	1,086
Gross margin	149	296	135	151	246	155	129	–	1,261
Operations, maintenance and administration	36	50	44	37	138	67	30	73	475
Depreciation and amortization	32	124	41	48	233	83	2	27	590
Asset impairment (reversal)	2	–	–	–	15	(10)	–	18	25
Gain on termination of Keephills 3 coal rights contract (Note 4(R))	–	–	–	–	(88)	–	–	–	(88)
Taxes, other than income taxes	3	8	1	–	13	3	–	1	29
Termination of Sundance B and C PPAs (Note 9)	–	–	–	–	(56)	–	–	–	(56)
Net other operating expense (income)	–	(10)	(1)	–	(40)	–	–	2	(49)
Operating income (loss)	76	124	50	66	31	12	97	(121)	335
Finance lease income	–	–	6	–	–	–	–	–	6
Net interest expense									(179)
Foreign exchange loss									(15)
Gain on sale of assets and other									46
Earnings before income taxes									193

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

Year ended Dec. 31, 2018	Hydro	Wind and Solar	North American Gas[1]	Australian Gas	Alberta Thermal[2]	Centralia[2]	Energy Marketing	Corporate	Total
Revenues	156	282	232	165	912	442	67	(7)	2,249
Fuel, carbon compliance and purchased power	6	17	96	8	666	314	–	(7)	1,100
Gross margin	150	265	136	157	246	128	67	–	1,149
Operations, maintenance and administration	38	50	48	37	171	61	24	86	515
Depreciation and amortization	30	110	43	49	241	74	2	25	574
Asset impairment	–	12	–	–	38	–	–	23	73
Taxes, other than income taxes	3	8	1	–	13	5	–	1	31
Termination of Sundance B and C PPAs (Note 9)	–	–	–	–	(157)	–	–	–	(157)
Net other operating income	–	(6)	–	–	(41)	–	–	–	(47)
Operating income (loss)	79	91	44	71	(19)	(12)	41	(135)	160
Finance lease income	–	–	8	–	–	–	–	–	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets									1
Earnings before income taxes									(96)

(1) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.
(2) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2020	**Hydro**	**Wind and Solar**	**North American Gas[2]**	**Australian Gas**	**Alberta Thermal[1]**	**Centralia[1]**	**Energy Marketing**	**Corporate**	**Total**
PP&E	**467**	**2,005**	**382**	**421**	**2,271**	**260**	**—**	**16**	**5,822**
Right-of-use assets	**6**	**55**	**1**	**4**	**53**	**—**	**—**	**22**	**141**
Intangible assets	**4**	**159**	**32**	**34**	**31**	**5**	**7**	**41**	**313**
Goodwill	**258**	**175**	**—**	**—**	**—**	**—**	**30**	**—**	**463**

As at Dec. 31, 2019	**Hydro**	**Wind and Solar**	**North American Gas[2]**	**Australian Gas**	**Alberta Thermal[1]**	**Centralia[1]**	**Energy Marketing**	**Corporate**	**Total**
PP&E	469	1,947	392	489	2,540	352	1	17	6,207
Right-of-use assets	6	56	—	4	68	—	—	12	146
Intangible assets	5	173	2	37	41	6	9	45	318
Goodwill	258	176	—	—	—	—	30	—	464

(1) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2020	**Hydro**	**Wind and Solar**	**North American Gas[2]**	**Australian Gas**	**Alberta Thermal[1]**	**Centralia[1]**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**22**	**174**	**39**	**10**	**200**	**28**	**—**	**13**	**486**
Intangible assets	**—**	**—**	**—**	**—**	**1**	**—**	**—**	**13**	**14**

Year ended Dec. 31, 2019	**Hydro**	**Wind and Solar**	**North American Gas[2]**	**Australian Gas**	**Alberta Thermal[1]**	**Centralia[1]**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	23	229	36	6	114	8	—	1	417
Intangible assets	—	—	—	—	2	—	—	12	14

Year ended Dec. 31, 2018	**Hydro**	**Wind and Solar**	**North American Gas[2]**	**Australian Gas**	**Alberta Thermal[1]**	**Centralia[1]**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	16	117	21	6	101	14	—	2	277
Intangible assets	—	—	—	—	3	—	—	17	20

(1) The Canadian Coal segment was renamed Alberta Thermal and the US Coal segment was renamed Centralia in the third quarter of 2020.
(2) This segment was previously known as the Canadian Gas segment but renamed with the acquisition of the US cogeneration facility in the second quarter of 2020. Refer to Note 4(K) for further details.

IV. Depreciation and Amortization on the Consolidated Statements of Cash Flows

The reconciliation between depreciation and amortization reported on the Consolidated Statements of Earnings (Loss) and the Consolidated Statements of Cash Flows is presented below:

Year ended Dec. 31	2020	2019	2018
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**654**	590	574
Depreciation included in fuel, carbon compliance and purchased power (Note 6)	**144**	119	136
Depreciation and amortization on the Consolidated Statements of Cash Flows	**798**	709	710

C. Geographic Information

I. Revenues

Year ended Dec. 31	2020	2019	2018
Canada	**1,227**	1,460	1,573
US	**716**	727	511
Australia	**158**	160	165
Total revenue	**2,101**	2,347	2,249

II. Non-Current Assets

	Property, plant and equipment		Right-of-use assets		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Canada	**4,661**	4,854	**107**	109	**185**	213	**74**	75	**418**	418
US	**737**	863	**30**	33	**94**	68	**61**	47	**45**	46
Australia	**424**	490	**4**	4	**34**	37	**71**	76	**—**	—
Total	**5,822**	6,207	**141**	146	**313**	318	**206**	198	**463**	464

D. Significant Customer

During the year ended Dec. 31, 2020, no sales to any one customer was greater than 10 per cent of the Corporation's total revenue (2019 – one customer within the Alberta Thermal and Hydro segments represented 11 per cent of total revenue).

Exhibit 1

(Unaudited)

The information set out below is referred to as "unaudited" as a means of clarifying that it is not covered by the audit opinion of the independent registered public accounting firm that has audited and reported on the Consolidated Financial Statements.

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2020:

Earnings coverage on long-term debt supporting the Corporation's Shelf Prospectus

(0.46) times

Earnings coverage on long-term debt on a net earnings basis is equal to net earnings before interest expense and income taxes, divided by interest expense including capitalized interest.