Consolidated Financial Statements

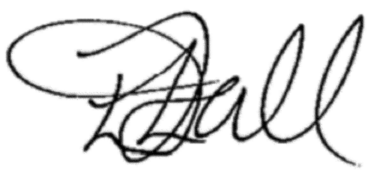
Management's Report

To the Shareholders of TransAlta Corporation

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

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

The Board of Directors (the "Board") is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal controls. The Board carries out its responsibilities principally through its Audit 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

Christophe Dehout
Chief Financial Officer

February 26, 2019

Management's Annual Report on Internal Control over Financial Reporting

To the Shareholders of TransAlta Corporation

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

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

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

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

TransAlta proportionately consolidates the accounts of the Sheerness and Genesee Unit 3 joint operations in accordance with International Financial Reporting Standards. Management does not have the contractual ability to assess the internal controls of these joint arrangements. Once the financial information is obtained from these joint arrangements it falls within the scope of TransAlta's internal controls framework. Management's conclusion regarding the effectiveness of internal controls does not extend to the internal controls at the transactional level of these joint arrangements. The 2018 Consolidated Financial Statements of TransAlta included $588 million and $521 million of total and net assets, respectively, as of December 31, 2018, and $244 million and $27 million of revenues and net loss, respectively, for the year then ended related to these joint arrangements.

Management has assessed the effectiveness of TransAlta's internal control over financial reporting, as at December 31, 2018, 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 December 31, 2018, has also issued a report on internal control over financial reporting under the standards of the Public Company Accounting Oversight Board (United States). This report is located on the following page of this Annual Report.

Dawn L. Farrell
President and Chief Executive Officer

Christophe Dehout
Chief Financial Officer

February 26, 2019

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, 2018, 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, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Consolidated Statements of Financial Position of TransAlta Corporation as of December 31, 2018 and 2017, 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, 2018 and the related notes and our report dated February 26, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

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

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

As indicated in the accompanying Management's Annual Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the Sheerness and Genesee Unit 3 joint arrangements, which are included in the 2018 consolidated financial statements of TransAlta and constituted $588 million and $521 million of total and net assets, respectively, as of December 31, 2018, and $244 million and $27 million of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of TransAlta Corporation did not include an evaluation of the internal control over financial reporting of the Sheerness and Genesee Unit 3 joint arrangements.

Ernst + Young LLP

Chartered Professional Accountants
Calgary, Canada
February 26, 2019

Independent Auditors' Report of 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 as of December 31, 2018 and 2017, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on internal control over financial reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), TransAlta Corporation's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 26, 2019 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 include 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.

Ernst + Young LLP

Chartered Professional Accountants
We have served as TransAlta Corporation and its predecessor entities' auditor since 1947
Calgary, Canada
February 26, 2019

Consolidated Statements of Earnings (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars except where noted)*	**2018**	2017	2016
Revenues (Note 5)	**2,249**	2,307	2,397
Fuel and purchased power (Note 6)	**1,100**	1,016	963
Gross margin	**1,149**	1,291	1,434
Operations, maintenance and administration (Note 6)	**515**	517	489
Depreciation and amortization	**574**	635	601
Asset impairment charges (reversals) (Note 7)	**73**	20	28
Taxes, other than income taxes	**31**	30	31
Net other operating expense (income) (Note 9)	**(204)**	(49)	(193)
Operating income	**160**	138	478
Finance lease income	**8**	54	66
Net interest expense (Note 10)	**(250)**	(247)	(229)
Foreign exchange gain (loss)	**(15)**	(1)	(5)
Gain on sale of assets and other	**1**	2	4
Earnings (loss) before income taxes	**(96)**	(54)	314
Income tax expense (recovery) (Note 11)	**(6)**	64	38
Net earnings (loss)	**(90)**	(118)	276
Net earnings (loss) attributable to:			
TransAlta shareholders	**(198)**	(160)	169
Non-controlling interests (Note 12)	**108**	42	107
	(90)	(118)	276
Net earnings (loss) attributable to TransAlta shareholders	**(198)**	(160)	169
Preferred share dividends (Note 25)	**50**	30	52
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Weighted average number of common shares outstanding in the year *(millions)*	**287**	288	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted (Note 24)	**(0.86)**	(0.66)	0.41

See accompanying notes.

Consolidated Statements of Comprehensive Income (Loss)

Year ended Dec. 31 *(in millions of Canadian dollars)*	**2018**	2017	2016
Net earnings (loss)	**(90)**	(118)	276
Other comprehensive income (loss)			
Net actuarial gains (losses) on defined benefit plans, net of tax(1)	**15**	(6)	8
Gains (losses) on derivatives designated as cash flow hedges, net of tax(2)	**—**	(1)	(1)
Total items that will not be reclassified subsequently to net earnings	**15**	(7)	7
Gains (losses) on translating net assets of foreign operations, net of tax(3)	**84**	(80)	(71)
Reclassification of translation gains on net assets of divested foreign operations(4) (Note 4)	**—**	(9)	—
Gains (losses) on financial instruments designated as hedges of foreign operations, net of tax(5)	**(41)**	50	18
Reclassification of losses on financial instruments designated as hedges of divested foreign operations, net of tax(6) (Note 4)	**—**	14	—
Gains (losses) on derivatives designated as cash flow hedges, net of tax(7)	**(8)**	214	179
Reclassification of gains on derivatives designated as cash flow hedges to net earnings, net of tax(8)	**(46)**	(107)	(48)
Total items that will be reclassified subsequently to net earnings	**(11)**	82	78
Other comprehensive income	**4**	75	85
Total comprehensive income (loss)	**(86)**	(43)	361
Total comprehensive income (loss) attributable to:			
TransAlta shareholders	**(210)**	(74)	215
Non-controlling interests (Note 12)	**124**	31	146
	(86)	(43)	361

(1) Net of income tax expense of 5 million for the year ended Dec. 31, 2018 (2017 - 4 million recovery, 2016 - 4 million expense).
(2) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - nil , 2016 - nil).
(3) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - nil, 2016 - 11 million expense).
(4) Net of reclassification of income tax of nil for the year ended Dec. 31, 2018 (2017 - 11 million expense, 2016 - nil).
(5) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 2 million expense, 2016 - 5 million expense).
(6) Net of reclassification of income tax of nil for the year ended Dec. 31, 2018 (2017 - 2 million recovery, 2016 - nil).
(7) Net of income tax recovery of 1 million for the year ended Dec. 31, 2018 (2017 - 77 million recovery, 2016 - 92 million expense).
(8) Net of reclassification of income tax expense of 11 million for the year ended Dec. 31, 2018 (2017 - 31 million expense, 2016 - 41 million expense).

See accompanying notes.

Consolidated Statements of Financial Position

As at Dec. 31 *(in millions of Canadian dollars)*	**2018**	2017
Cash and cash equivalents	**89**	314
Restricted cash (Note 22)	**66**	—
Trade and other receivables (Note 13)	**756**	933
Prepaid expenses	**13**	24
Risk management assets (Note 14 and 15)	**146**	219
Inventory (Note 16)	**242**	219
	1,312	1,709
Restricted cash (Note 22)	**—**	30
Long-term portion of finance lease receivables (Note 8)	**191**	215
Property, plant and equipment (Note 17)		
Cost	**13,202**	12,973
Accumulated depreciation	**(7,038)**	(6,395)
	6,164	6,578
Goodwill (Note 18)	**464**	463
Intangible assets (Note 19)	**373**	364
Deferred income tax assets (Note 11)	**28**	24
Risk management assets (Note 14 and 15)	**662**	684
Other assets (Note 20)	**234**	237
Total assets	**9,428**	10,304
Accounts payable and accrued liabilities	**497**	595
Current portion of decommissioning and other provisions (Note 21)	**70**	67
Risk management liabilities (Note 14 and 15)	**90**	101
Income taxes payable	**10**	64
Dividends payable (Note 24 and 25)	**58**	34
Current portion of long-term debt and finance lease obligations (Note 22)	**148**	747
	873	1,608
Credit facilities, long-term debt and finance lease obligations (Note 22)	**3,119**	2,960
Decommissioning and other provisions (Note 21)	**386**	403
Deferred income tax liabilities (Note 11)	**501**	549
Risk management liabilities (Note 14 and 15)	**41**	40
Contract liabilities (Note 5)	**87**	62
Defined benefit obligation and other long-term liabilities (Note 23)	**287**	297
Equity		
Common shares (Note 24)	**3,059**	3,094
Preferred shares (Note 25)	**942**	942
Contributed surplus	**11**	10
Deficit	**(1,496)**	(1,209)
Accumulated other comprehensive income (Note 26)	**481**	489
Equity attributable to shareholders	**2,997**	3,326
Non-controlling interests (Note 12)	**1,137**	1,059
Total equity	**4,134**	4,385
Total liabilities and equity	**9,428**	10,304

Commitments and contingencies (Note 33)

On behalf of the Board:

Gordon D. Giffin
Director

Beverlee F. Park
Director

See accompanying notes.

Consolidated Statements of Changes in Equity

(in millions of Canadian dollars)

	Common shares	Preferred shares	Contributed surplus	Deficit	Accumulated other comprehensive income[1]	Attributable to shareholders	Attributable to non-controlling interests	Total
Balance, Dec. 31, 2016	3,094	942	9	(933)	399	3,511	1,152	4,663
Net earnings	—	—	—	(160)	—	(160)	42	(118)
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	—	—	—	—	(25)	(25)	—	(25)
Net gains on derivatives designated as cash flow hedges, net of tax	—	—	—	—	106	106	—	106
Net actuarial gains on defined benefits plans, net of tax	—	—	—	—	(6)	(6)	—	(6)
Intercompany available-for-sale investments	—	—	—	—	11	11	(11)	—
Total comprehensive income				(160)	86	(74)	31	(43)
Common share dividends	—	—	—	(34)	—	(34)	—	(34)
Preferred share dividends	—	—	—	(30)	—	(30)	—	(30)
Changes in non-controlling interests in TransAlta Renewables (Note 4)	—	—	—	(52)	4	(48)	48	—
Effect of share-based payment plans	—	—	1	—	—	1	—	1
Distributions paid, and payable, to non-controlling interests	—	—	—	—	—	—	(172)	(172)
Balance, Dec. 31, 2017	3,094	942	10	(1,209)	489	3,326	1,059	4,385
Impact of change in accounting policy (Note 3)	**—**	**—**	**—**	**(14)**	**—**	**(14)**	**1**	**(13)**
Adjusted balance as at Jan. 1, 2018	**3,094**	**942**	**10**	**(1,223)**	**489**	**3,312**	**1,060**	**4,372**
Net earnings (loss)	**—**	**—**	**—**	**(198)**	**—**	**(198)**	**108**	**(90)**
Other comprehensive income (loss):								
Net losses on translating net assets of foreign operations, net of hedges and of tax	**—**	**—**	**—**	**—**	**43**	**43**	**—**	**43**
Net gains on derivatives designated as cash flow hedges, net of tax	**—**	**—**	**—**	**—**	**(54)**	**(54)**	**—**	**(54)**
Net actuarial gains on defined benefits plans, net of tax	**—**	**—**	**—**	**—**	**15**	**15**	**—**	**15**
Intercompany fair value through other comprehensive income investments	**—**	**—**	**—**	**—**	**(16)**	**(16)**	**16**	**—**
Total comprehensive income				**(198)**	**(12)**	**(210)**	**124**	**(86)**
Common share dividends	**—**	**—**	**—**	**(57)**	**—**	**(57)**	**—**	**(57)**
Preferred share dividends	**—**	**—**	**—**	**(50)**	**—**	**(50)**	**—**	**(50)**
Shares purchased under NCIB	**(35)**	**—**	**—**	**12**	**—**	**(23)**	**—**	**(23)**
Changes in non-controlling interests in TransAlta Renewables (Note 4)	**—**	**—**	**—**	**20**	**4**	**24**	**133**	**157**
Effect of share-based payment plans	**—**	**—**	**1**	**—**	**—**	**1**	**—**	**1**
Distributions paid, and payable, to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(180)**	**(180)**
Balance, Dec.31, 2018	**3,059**	**942**	**11**	**(1,496)**	**481**	**2,997**	**1,137**	**4,134**

(1) Refer to Note 26 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)*	**2018**	2017	2016
Operating activities			
Net earnings (loss)	**(90)**	(118)	276
Depreciation and amortization (Note 34)	**710**	708	664
Gain (loss) on sale of assets (Note 4)	**—**	(1)	(1)
Accretion of provisions (Note 21)	**24**	23	20
Decommissioning and restoration costs settled (Note 21)	**(31)**	(19)	(23)
Deferred income tax expense (recovery) (Note 11)	**(34)**	(15)	15
Unrealized (gain) loss from risk management activities	**30**	(48)	58
Unrealized foreign exchange (gain) loss	**28**	22	(1)
Provisions	**7**	(7)	(123)
Asset impairment charges (reversals) (Note 7)	**73**	20	28
Other non-cash items	**147**	175	(242)
Cash flow from operations before changes in working capital	**864**	740	671
Change in non-cash operating working capital balances (Note 30)	**(44)**	(114)	73
Cash flow from operating activities	**820**	626	744
Investing activities			
Additions to property, plant and equipment (Note 17 and 34)	**(277)**	(338)	(358)
Additions to intangibles (Note 19 and 34)	**(20)**	(51)	(21)
Restricted cash (Note 22)	**(35)**	(30)	—
Loan receivable (Note 20)	**1**	(38)	—
Acquisition of renewable energy facilities, net of cash acquired (Note 4)	**(30)**	—	—
Proceeds on sale of property, plant and equipment	**2**	3	6
Proceeds on sale of Wintering Hills facility and Solomon disposition (Note 4)	**2**	478	—
Income tax expense on Solomon disposition (Note 4 and 11)	**—**	(56)	—
Realized gains (losses) on financial instruments	**2**	6	(6)
Decrease in finance lease receivable	**59**	59	56
Other	**(2)**	(3)	2
Change in non-cash investing working capital balances	**(96)**	57	(6)
Cash flow from (used in) investing activities	**(394)**	87	(327)
Financing activities			
Net increase (decrease) in borrowings under credit facilities (Note 22)	**312**	26	(315)
Repayment of long-term debt (Note 22)	**(1,179)**	(814)	(88)
Issuance of long-term debt (Note 22)	**345**	260	361
Dividends paid on common shares (Note 24)	**(46)**	(46)	(69)
Dividends paid on preferred shares (Note 25)	**(40)**	(40)	(42)
Net proceeds on sale of non-controlling interest in subsidiary (Note 4)	**144**	—	162
Repurchase of common shares under NCIB (Note 24)	**(23)**	—	—
Realized gains (losses) on financial instruments	**48**	106	(2)
Distributions paid to subsidiaries' non-controlling interests (Note 12)	**(165)**	(172)	(151)
Decrease in finance lease obligations (Note 22)	**(18)**	(17)	(16)
Other	**(31)**	(6)	(3)
Change in non-cash financing working capital balances	**2**	—	—
Cash flow from (used in) financing activities	**(651)**	(703)	(163)
Cash flow from (used in) operating, investing, and financing activities	**(225)**	10	254
Effect of translation on foreign currency cash	**—**	(1)	(3)
Increase (decrease) in cash and cash equivalents	**(225)**	9	251
Cash and cash equivalents, beginning of year	**314**	305	54
Cash and cash equivalents, end of year	**89**	314	305
Cash income taxes paid	**87**	14	27
Cash interest paid	**188**	230	235

See accompanying notes.

1. Corporate Information

A. Description of the Business

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

I. Generation Segments

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

II. Energy Marketing Segment

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

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

III. Corporate

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

B. Basis of Preparation

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

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

These consolidated financial statements were authorized for issue by TransAlta's Board of Directors (the "Board") on February 26, 2019.

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 Corporation has adopted IFRS 15 *Revenue from Contracts with Customers* (IFRS 15) with an initial adoption date of Jan. 1, 2018. As a result, the Corporation has changed its accounting policy for revenue recognition, which is outlined below.

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

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

Performance Obligations

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

Transaction Price

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

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

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

Good or Service	***Description***
Capacity	Capacity refers to the availability of an asset to deliver goods or services. Customers typically pay for capacity for each defined time period (i.e., monthly) in an amount representative of availability of the asset for the defined time period. Obligations to deliver capacity are satisfied over time and revenue is recognized using a time-based measure. Contracts for capacity are typically long term in nature. Payments are typically received from customers on a monthly basis.
Contract Power	The sale of contract power refers to the delivery of units of electricity to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver electricity are satisfied over time and revenue is recognized using a units-based output measure (i.e., megawatt hours). Contracts for power are typically long term in nature and payments are typically received on a monthly basis.
Thermal Energy	Thermal energy refers to the delivery of units of steam to a customer under the terms of a contract. Customers pay a contractually specified price for the output at the end of predefined contractual periods (i.e., monthly). Obligations to deliver steam are satisfied over time and revenue is recognized using a units-based output measure (i.e., gigajoules). Contracts for thermal energy are typically long term in nature. Payments are typically received from customers on a monthly basis.
Renewable Attributes	Renewable attributes refers to the delivery of renewable energy certificates, green attributes and other similar items. Customers may contract for renewable 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 renewable attributes. Obligations to deliver renewable 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.

The Corporation recognizes a contract asset or contract liability for contracts where either party has performed. 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.

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

Transaction price
In determining the transaction price and estimates of variable consideration, management considers past history of customer usage and capacity requirements, in estimating the goods and services to be provided to the customer. The Corporation also considers the historical production levels and operating conditions for its variable generating assets.

Allocation of transaction price to performance obligations
The Corporation's contracts generally outline a specific amount to be invoiced to a customer associated with each performance obligation in the contract. Where contracts do not specify amounts for individual performance obligations, the Corporation estimates the amount of the transaction price to allocate to individual performance obligations based on their standalone selling price, which is primarily estimated based on the amounts that would be charged to customers under similar market conditions.

Satisfaction of performance obligations
The satisfaction of performance obligations requires management to use judgment as to when control of the underlying good or service transfers to the customer. Determining when a performance obligation is satisfied affects the timing of revenue recognition. Management considers both customer acceptance of the good or service, and the impact of laws and regulations such as certification requirements, in determining when this transfer occurs. Management also applies judgment in determining whether the invoice practical expedient can be relied upon in measuring progress toward complete satisfaction of performance obligations. 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.

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

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

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

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

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

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

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

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

Classification and Measurement

IFRS 9 introduces 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 ("FVTOCI").

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

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

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 accounted for on the Consolidated Statements of Financial Position at fair value, with subsequent changes in fair value recorded in net earnings in the period of change.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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.

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

Coal generation	2-12 years
Gas generation	2-30 years
Hydro generation	3-60 years
Wind generation	3-30 years
Mining property and equipment	2-12 years
Capital spares and other	2-30 years

TransAlta capitalizes borrowing costs on capital invested in projects under construction (see Note 2(S)). 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 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 useful lives of intangible assets are as follows:

Software	2-7 years
Power sale contracts	5-20 years

I. Impairment of Tangible and Intangible Assets Excluding Goodwill

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

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

The Corporation's operations, the market and business environment are routinely monitored, and judgments and assessments are made to determine whether an event has occurred that indicates a possible impairment. If such an event has occurred, an estimate is made of the recoverable amount of the asset or cash-generating unit ("CGU") to which the asset belongs. Recoverable amount is the higher of an asset's fair value less costs of disposal and its value in use. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. In determining fair value, recent market transactions are taken into account. If no such transactions can be identified, an appropriate valuation model such as discounted cash flows is used. Value in use is the present value of the estimated future cash flows expected to be derived from the asset from its continued use and ultimate disposal by the Corporation. If the recoverable amount is less than the carrying amount of the asset or CGU, an asset impairment loss 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 loss 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 loss previously recognized is reversed. Where an impairment loss 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 loss been recognized previously. A reversal of an impairment loss 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 indicate 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 loss 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 loss 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 other assets. The appropriateness of capitalization of these costs is evaluated each reporting period, and amounts capitalized for projects no longer probable of occurring are charged to net earnings.

L. Income Taxes

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

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

M. Employee Future Benefits

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

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

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

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

N. Provisions

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

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

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

O. Share-Based Payments

The Corporation measures share-based awards compensation expense at grant date 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. 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. 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.

Q. 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.

R. Leases

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.

Power purchase arrangements ("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.

S. Borrowing Costs
TransAlta 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.

T. 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.

U. 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. TransAlta'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 loss 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.

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. 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.

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. 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 loss may exist or that a previously recognized impairment loss 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 2016 to 2018 is found in Notes 7 and 18.

II. Leases
In determining whether the Corporation's PPAs and other long-term electricity and thermal sales contracts contain, or are, leases, management must use judgment in assessing whether the fulfilment of the arrangement is dependent on the use of a specific asset and the arrangement conveys the right to use the asset. For those agreements considered to contain, or be, leases, further judgment is required to determine whether substantially all of the significant risks and rewards of ownership are transferred to the customer or remain with the Corporation, to appropriately account for the agreement as either a finance or operating lease. These judgments can be significant and impact how the Corporation classifies amounts related to the arrangement as either PP&E or as a finance lease receivable on the Consolidated Statements of Financial Position, and therefore the amount of certain items of revenue and expense is dependent upon such classifications.

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

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

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

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

VI. Provisions for Decommissioning and Restoration Activities
TransAlta recognizes provisions for decommissioning and restoration obligations as outlined in Note 2(N) and Note 21. 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.

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

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

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

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

Due to the complexity of the valuation of pension and post-employment benefits, a change in the estimate of any one of these factors could have a material effect on the carrying amount of the liability for pension and other post-employment benefits or the related expense. These assumptions are reviewed annually to ensure they continue to be appropriate. See Note 28 for disclosures on employee future benefits.

IX. Other Provisions
Where necessary, TransAlta recognizes provisions arising from ongoing business activities, such as interpretation and application of contract terms, ongoing litigation and force majeure claims. These provisions, and subsequent changes thereto, are determined using the Corporation's best estimate of the outcome of the underlying event and can also be impacted by determinations made by third parties, in compliance with contractual requirements. The actual amount of the provisions that may be required could differ materially from the amount recognized. More information is disclosed in Notes 4 and 21 with respect to other provisions.

3. Accounting Changes

A. Current Accounting Changes

I. IFRS 15 *Revenue from Contracts with Customers*

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15"), which replaces existing revenue recognition guidance with a single comprehensive accounting model. The model specifies that an entity recognizes revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which it expects to be entitled in exchange for those goods or services. In April 2016, the IASB issued an amendment to IFRS 15 to clarify the identification of performance obligations, principal versus agent considerations, licenses of intellectual property and transition practical expedients. IFRS 15, including the amendment, is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after Jan. 1, 2018, with earlier adoption permitted.

The Corporation has adopted IFRS 15 with an initial adoption date of Jan. 1, 2018. As a result, the Corporation has changed its accounting policy for revenue recognition, which is outlined in Note 2(A).

The Corporation has elected to adopt IFRS 15 retrospectively with the modified retrospective method of transition practical expedient and has elected to apply IFRS 15 only to contracts that are not completed contracts at the date of initial application. Comparative information has not been restated and is reported under IAS 18 *Revenue* ("IAS 18"), which is outlined in Note 2(A)(iii).

The Corporation recognized the cumulative impact of the initial application of the standard in the deficit as at Jan. 1, 2018. Applying the significant financing component requirements to a specific contract resulted in an increase to the contract liability of $17 million, a decrease in deferred income tax liabilities of $4 million and an increase to the deficit of $13 million. IFRS 15 requires that, in determining the transaction price, the promised amount of consideration is to be adjusted for the effects of the time value of money if the timing of payments specified in a contract provides either party with a significant benefit of financing the transfer of goods or services to the customer (“significant financing component”). The objective when adjusting the promised amount of consideration for a significant financing component is to recognize revenue at an amount that reflects the price that the customer would have paid, had they paid cash in the future when the goods or services are transferred to them. The application of the significant financing component requirement results in the recognition of interest expense over the financing period and a higher amount of revenue.

Additionally, the Corporation no longer recognizes revenue (or fuel costs) related to non-cash consideration for natural gas supplied by a customer at one of its gas plants , as it was determined under IFRS 15 that the Corporation does not obtain control of the customer-supplied natural gas.

Refer to the discussion in Note 2(A) and in Note 5 for a breakdown of the Corporation's revenues from contracts with customers and revenues from other sources.

The following tables summarize the financial statement line items impacted by adopting IFRS 15 as at and for the year ended Dec. 31, 2018:

Condensed Consolidated Statement of Earnings (Loss)

Year ended Dec. 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Revenues	2,253	(4)	2,249
Fuel, carbon costs and purchased power	(1,109)	9	(1,100)
Net interest expense	(243)	(7)	(250)
Net earnings impact	(88)	(2)	(90)

Condensed Consolidated Statements of Financial Position

As at Dec. 31, 2018	Reported in accordance with IAS 18 and IAS 11	Adjustments	As reported under IFRS 15
Deferred income tax liabilities	505	(4)	501
Contract liability	68	19	87
Deficit	(1,481)	(15)	(1,496)

There were no impacts to the statement of cash flows as a result of adopting IFRS 15.

II. IFRS 9 *Financial Instruments*

Effective Jan. 1, 2018, the Corporation adopted IFRS 9, which introduces new requirements for:

- the classification and measurement of financial assets and liabilities;
- the recognition and measurement of impairment of financial assets; and
- general hedge accounting.

In accordance with the transition provisions of the standard, the Corporation has elected to not restate prior periods. The impact of adopting IFRS 9 was recognized in the deficit at Jan. 1, 2018. While the Corporation had no direct impact of adopting IFRS 9, a $1 million increase in the deficit resulted from the increase in equity attributable to non-controlling interests due to IFRS 9 impacts at TransAlta Renewables Inc. ("TransAlta Renewables").

The Corporation's accounting policies under IFRS 9 are outlined in Note 2(C) and the key impacts are outlined below. For more information on the Corporation's accounting policies under IAS 39 for the period ended Dec. 31, 2017, refer to note 2 of the Corporation's 2017 annual consolidated financial statements.

a. Classification and Measurement

IFRS 9 introduces 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 FVTPL, or at FVTOCI. Refer to Note 2 (C) for further details.

The Corporation's management reviewed and assessed the classifications of its existing financial instruments as at Jan. 1, 2018, based on the facts and circumstances that existed at that date, as shown below. None of the reclassifications had a significant impact on the Corporation's financial position, earnings (loss), other comprehensive income (loss) or total comprehensive income (loss) after the date of initial application.

Financial instrument	IAS 39 category	IFRS 9 classification
Cash and cash equivalents	Loans and receivables	Amortized cost
Restricted cash	Loans and receivables	Amortized cost
Trade and other receivables	Loans and receivables	Amortized cost
Long-term portion of finance lease receivables	Loans and receivables	Amortized cost
Loan receivable (other assets)	Loans and receivables	Amortized cost
Risk management assets (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management assets (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Accounts payable and accrued liabilities	Other financial liabilities	Amortized cost
Dividends payable	Other financial liabilities	Amortized cost
Risk management liabilities (current and long-term) - derivatives held for trading	Held for trading	FVTPL
Risk management liabilities (current and long-term) - derivatives designated as hedging instruments	Derivatives designated as hedging instruments	FVOCI
Credit facilities and long-term debt	Other financial liabilities	Amortized cost

b. Impairment of Financial Assets
IFRS 9 introduces a new impairment model for financial assets measured at amortized cost as well as certain other instruments. The expected credit loss model requires entities to account for expected credit losses on financial assets at the date of initial recognition, and to account for changes in expected credit losses at each reporting date to reflect changes in credit risk.

The Corporation's management reviewed and assessed its existing financial assets for impairment using reasonable and supportable information in accordance with the requirements of IFRS 9 to determine the credit risk of the respective items at the date they were initially recognized, and compared that to the credit risk as at Jan. 1, 2018. There were no significant increases in credit risk determined upon application of IFRS 9 and no loss allowance was recognized.

c. General Hedge Accounting
IFRS 9 retains the three types of hedges from IAS 39 (fair value hedges, cash flow hedges and hedges of a net investment in a foreign operation), but increases flexibility as to the types of transactions that are eligible for hedge accounting.

The effectiveness test of IAS 39 is replaced by the principle of an "economic relationship", which requires that the hedging instrument and the hedged item have values that generally move in opposite direction because of the hedged risk. Additionally, retrospective hedge effectiveness testing is no longer required under IFRS 9.

In accordance with IFRS 9's transition provisions for hedge accounting, the Corporation has applied the IFRS 9 hedge accounting requirements prospectively from the date of initial application on Jan. 1, 2018, and comparative figures have not been restated. The Corporation's qualifying hedging relationships under IAS 39 in place as at Jan. 1, 2018 also qualified for hedge accounting in accordance with IFRS 9, and were therefore regarded as continuing hedging relationships. No rebalancing of any of the hedging relationships was necessary on Jan. 1, 2018. As the critical terms of the hedging instruments match those of their corresponding hedged items, all hedging relationships continue to be effective under IFRS 9's effectiveness assessment. The Corporation has not designated any hedging relationships under IFRS 9 that would not have met the qualifying hedge accounting criteria under IAS 39. Further details of the Corporation's hedging activities are disclosed in Notes 14 and 15.

The Corporation's risk management objective and strategy, including risk management instruments and their key terms, are detailed in Notes 15A and 15C.

In certain cases, the Corporation purchases non-financial items in a foreign currency, for which it may enter into forward contracts to hedge foreign currency risk on the anticipated purchases. Both IAS 39 and IFRS 9 require hedging gains and losses to be basis adjusted to the initial carrying amount of non-financial hedged items once recognized (such as PP&E), but under IFRS 9, these adjustments are no longer considered reclassification adjustments and do not affect OCI. Under IFRS 9, these amounts will be directly transferred to the asset and will be reflected in the statement of changes in equity as a reclassification from AOCI.

The application of IFRS 9 hedge accounting requirements has no other impact on the results and financial position of the Corporation for the current or prior years.

III. Change in Estimates - Useful Lives
As a result of the Off-Coal Agreement ("OCA") with the Government of Alberta described in Note 4(O), the Corporation has adjusted the useful lives of some of its mine assets to align with the Corporation's coal-to-gas conversion plans. In addition, on Jan. 1, 2017, the useful lives of the PP&E and amortizable intangibles associated with some of the Corporation's Alberta coal assets were reduced to 2030. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2018, increased by approximately $38 million (2017 - $58 million). The useful lives may be revised or extended in compliance with the Corporation's accounting policies, dependent upon future operating decisions and events, such as coal-to-gas conversions.

Due to the Corporation's decision to retire Sundance Unit 1 effective Jan. 1, 2018 (see Note 4(A) for further details), the useful lives of the Sundance Unit 1 PP&E and amortizable intangibles were reduced in the second quarter of 2017 by two years to Dec. 31, 2018. As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, increased by approximately $26 million.

Since Sundance Unit 1 was shut down two years early, the Canadian federal Minister of Environment & Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. As such, during the third quarter of 2017, the Corporation extended the life of Sundance Unit 2 to 2021 (see Note 4(A) for further details). As a result, depreciation expense and intangibles amortization for the year ended Dec. 31, 2017, decreased in total by approximately $4 million. However, in the third quarter of 2018, the Corporation retired Sundance Unit 2 and recorded an impairment loss for the remaining net book value of the asset (see Note 4(A) and Note 7 for further details).

B. Future Accounting Changes

Accounting standards that have been previously issued by the IASB, but are not yet effective and have not been applied by the Corporation include IFRS 16 *Leases.* In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the statement of financial position, while operating leases are not. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. In addition, the nature and timing of expenses related to leases will change, as IFRS 16 replaces the straight-line operating leases expense with the depreciation expense for the assets and interest expense on the lease liabilities. For lessors, the accounting remains essentially unchanged.

IFRS 16 is effective for annual periods beginning on or after Jan. 1, 2019. The standard is required to be adopted either retrospectively or using a modified retrospective approach. On transition, TransAlta has elected to apply IFRS 16 using the modified retrospective approach effective Jan. 1, 2019. In applying IFRS 16 for the first time, the Corporation has used the following practical expedients permitted by the standard:

- Exemption for short-term leases that have a remaining lease term of less than 12 months as at Jan. 1, 2019 and low value leases;
- Excluding initial direct costs for the measurement of the right-of-use asset at the date of initial application;
- Using hindsight in determining the lease term where the contract contains options to extend or terminate the lease;
- Adjusting the right-of-use assets by the amount of IAS 37 onerous contract provision immediately before the date of initial application; and
- Measuring the right-of-use assets at an amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognized in the statement of financial position immediately before the date of initial application.

The Corporation has substantially completed its assessment of existing operating leases. The Corporation estimates that we will recognize right-of-use lease assets and related lease liabilities for existing operating leases where we are the lessee in the range of $42 million to $52 million. These changes will be partially offset by the derecognition of a finance lease asset and a finance lease liability related to a contractual arrangement that was accounted for as a finance lease under IAS 17 but is no longer considered a lease under IFRS 16.

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 Events

A. Transition to Clean Power in Alberta

I. Alberta Renewable Energy Program Project - Windrise

In the fourth quarter of 2018, TransAlta's 207 MW Windrise wind project was selected by the Alberta Electric System Operator ("AESO") as one of the three successful projects in the third round of the Renewable Electricity Program. The Windrise facility, which is in the county of Willow Creek, is underpinned by a 20-year Renewable Electricity Support Agreement with the AESO. The project is expected to cost approximately $270 million and is targeted to reach commercial operation during the second quarter of 2021.

II. Gas Supply for Coal-to-Gas Conversions

On Dec. 17, 2018, the Corporation exercised its option to acquire 50 percent ownership in the Pioneer gas pipeline ("Pioneer Pipeline"). Tidewater Midstream and Infrastructure Ltd. ("Tidewater") will construct and operate the 120 km natural gas pipeline, which will have an initial throughput of 130 MMcf/d with the potential to expand to approximately 440 MMcf/d. The Pioneer Pipeline will allow TransAlta to increase the amount of natural gas it co-fires at its Sundance and Keephills coal-fired units, resulting in lower carbon emissions and costs. As well, the Pioneer Pipeline will provide a significant amount of the gas required for the full conversion of the coal units to natural gas. The investment for TransAlta will amount to approximately $90 million. Construction of the pipeline commenced in November 2018 and the Pioneer Pipeline is expected to be fully operational by the second half of 2019. TransAlta's investment is subject to final regulatory approvals, which are expected to be received in the first half of 2019.

The decision to work with Tidewater advances the time frame for the construction of the Pioneer Pipeline and permits the acceleration of plant conversions. TransAlta remains of the view that having at least two pipelines supplying natural gas would reduce operational risks and continues to advance discussions with other parties to construct additional pipelines to meet the remaining gas supply requirements for the facilities.

III. Sundance and Keephills Units 1 and 2 Coal-to-Gas Conversion Strategy
On Dec. 6, 2017, the Corporation updated its strategy to accelerate its transition to gas and renewables generation. During 2018, the Corporation mothballed and retired the following Sundance Units:

- retired Sundance Unit 1 on Jan. 1, 2018;
- retired Sundance Unit 2 on July 31, 2018;
- temporarily mothballed Sundance Unit 3 on April 1, 2018, for a period of up to two years; and
- temporarily mothballed Sundance Unit 5 on April 1, 2018, for a period of up to one year, which has now been extended to two years.

TransAlta is no longer planning to temporarily mothball Sundance Unit 4 and will perform maintenance during the first half of 2019.

On December 18, 2018, the federal government published the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*. The regulations provide rules for new gas-fired electricity facilities, as well as specific provisions for coal-to-gas conversions. In addition to extending their operating lives, the benefits of converting units to gas generation include: significantly lowering carbon emissions and costs; significantly lowering operating and sustaining capital costs; and increasing operating flexibility. TransAlta expects to convert some or all of its Sundance Units 3 to 6 and Keephills Units 1 to 3 in the 2020 to 2023 period.

IV. Sundance Units 1 and 2
Canadian federal regulations stipulate that all coal plants built before 1975 must cease to operate on coal by the end of 2019, which includes Sundance Units 1 and 2. Given that Sundance Unit 1 was shut down two years early, the federal Minister of Environment & Climate Change agreed to extend the life of Sundance Unit 2 from 2019 to 2021. This provided the Corporation with the flexibility to respond to the regulatory environment for coal-to-gas conversions and the new upcoming Alberta capacity market. However, in July 2018, TransAlta retired Sundance Unit 2. This decision was driven largely by Sundance Unit 2's age, size and short useful life relative to other units, and the capital requirements needed to return the unit to service.

Sundance Units 1 and 2 collectively made up 560 MW of the 2,141 MW capacity of the Sundance power plant, which serves as a baseload provider for the Alberta electricity system. The PPA with the Balancing Pool relating to Sundance Units 1 and 2 expired on Dec. 31, 2017.

In the third quarter of 2018, the Corporation recognized an impairment charge of $38 million ($28 million after-tax) relating to the retirement of Sundance Unit 2. During the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 of $20 million ($15 million after-tax) due to the Corporation's decision to early retire Sundance Unit 1. See Note 7 for further details.

B. Kent Hills 3 Wind Project
During 2017, a subsidiary of TransAlta Renewables, Kent Hills Wind LP ("KHWLP"), entered into a long-term contract with New Brunswick Power Corporation ("NB Power") for the sale of all power generated by an additional 17.25 MW of capacity from the Kent Hills 3 expansion wind project. At the same time, the term of the Kent Hills 1 contract with NB Power was extended from 2033 to 2035, matching the life of the Kent Hills 2 and Kent Hills 3 wind projects.

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

C. Acquisition of Two US Wind Projects

On Feb. 20, 2018, TransAlta Renewables announced it had entered into an arrangement to acquire two construction-ready projects in the Northeastern United States. The wind development projects consist of: i) a 90 MW project located in Pennsylvania that has a 15-year PPA with Microsoft Corp. ("Big Level"), and ii) a 29 MW project located in New Hampshire with two 20-year PPAs ("Antrim") (collectively, the "US Wind Projects"), with counterparties that have Standard & Poor's credit ratings of A+ or better. The commercial operation date for both projects is expected during the second half of 2019. A subsidiary of TransAlta acquired Big Level on Feb. 20, 2018,and the acquisition of Antrim remains subject to certain closing conditions, including the receipt of a favourable regulatory ruling. The Corporation expects the Antrim acquisition to close in early 2019.

On April 20, 2018, TransAlta Renewables completed the acquisition of an economic interest in the US Wind Projects from a subsidiary of TransAlta (“TA Power”). Pursuant to the arrangement, a TransAlta subsidiary owns the US Wind Projects directly and TA Power issued to TransAlta Renewables tracking preferred shares that pay quarterly dividends based on the pre-tax net earnings of the US Wind Projects. The tracking preferred shares have preference over the common shares of TA Power held by TransAlta, in respect of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of TA Power. The construction and acquisition costs of the two US Wind Projects are expected to be funded by TransAlta Renewables and a $25 million promissory note receivable and are estimated to be US$240 million. TransAlta Renewables will fund these costs either by acquiring additional preferred shares issued by TA Power or by subscribing for interest-bearing notes issued by the project entity. The proceeds from the issuance of such preferred shares or notes will be used exclusively in connection with the acquisition and construction of the US Wind Projects. TransAlta Renewables expects to fund these acquisition and construction costs using its existing liquidity and tax equity.

During the year ended Dec. 31, 2018, TransAlta Renewables funded approximately $61 million (US$48 million) of construction costs. On Jan. 2, 2019, TransAlta Renewables funded an additional $45 million (US$33 million) of construction costs.

D. TransAlta Renewables Acquires Three Renewable Assets from the Corporation

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

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

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

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

E. TransAlta Renewables Closes $150 Million Offering of Common Shares

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

The net proceeds 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 is to be used for general corporate purposes, including ongoing construction costs associated with the US Wind Projects, described in 4(C) above.

The Corporation did not purchase any additional common shares under the Offering and, following the closing, owned 161 million common shares, representing approximately 61 per cent of the outstanding common shares of TransAlta Renewables. See Note 12 for further details of TransAlta's ownership of TransAlta Renewables.

F. $345 Million Financing

On July 20, 2018, the Corporation monetized the payments under the 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 below.

G. Early Redemption of $400 Million of Debentures

On Aug. 2, 2018, the Corporation early redeemed all of its then outstanding 6.40 per cent debentures, due Nov. 18, 2019, for the principal amount of$400 million. The redemption price was approximately $425 million in aggregate, including a prepayment premium and accrued and unpaid interest. See Note 22 for further details.

H. Normal Course Issuer Bid

On March 9, 2018 the Corporation announced that the Toronto Stock Exchange ("TSX") accepted the notice filed by the Corporation to implement a normal course issuer bid ("NCIB") for a portion of its common shares. Pursuant to the NCIB, the Corporation may 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. 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. Common shares purchased under the NCIB are cancelled.

The period during which TransAlta is authorized to make purchases under the NCIB commenced on March 14, 2018, and ends on March 13, 2019, 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 than102,039 common shares (being 25 per cent of the average daily trading volume on the TSX of 408,156 common shares for the six months ended February 28, 2018) 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, 2018, the Corporation purchased and cancelled 3,264,500 common shares at an average price of $7.02 per common share, for a total cost of $23 million. See Note 24 for further details. Further transactions, if any, under the NCIB will depend on market conditions. The Corporation retains discretion whether to make purchases under the NCIB, and to determine the timing, amount and acceptable price of any such purchases, subject at all times to applicable TSX and other regulatory requirements.

I. Early Redemption of Senior Notes

On March 15, 2018, the Corporation early redeemed all of its outstanding 6.650 per cent US $500 million senior notes due May 15, 2018, for approximately $617 million (US$516 million). A $5 million early redemption premium was recognized in net interest expense. See Note 22 for further details.

J. Balancing Pool Provides Notice to Terminate the Alberta Sundance Power Purchase Arrangements

On Sept 18. 2017, the Corporation received formal notice from the Balancing Pool for the termination of the Sundance B and C PPAs effective 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 is disputing the termination payment it received. The Balancing Pool excluded certain mining assets that the Corporation believes should be included in the net book value calculation for an additional termination payment of $56 million. The dispute is currently proceeding through the PPA arbitration process.

K. Notice of Termination of South Hedland Power Purchase Agreement from Fortescue Metals Group Limited

On Nov. 13, 2017, the Corporation announced that TEC Hedland Pty Ltd ("TEC Hedland"), a subsidiary of the Corporation, received formal notice of termination of the South Hedland Power Purchase Agreement ("South Hedland PPA") from a subsidiary of Fortescue Metals Group Limited ("FMG"). The South Hedland PPA allows FMG to terminate the agreement if the power station has not reached commercial operation within a specified time period. FMG continues to be of the view that South Hedland Power Station has yet to achieve commercial operation.

The Corporation believes that all conditions required to establish commercial operations, including all performance conditions, have been achieved under the terms of the South Hedland PPA. These conditions include receiving a commercial operation certificate, successfully completing and passing certain test requirements, and obtaining all permits and approvals required from the North West Interconnected System and government agencies. Confirmation of commercial operation has been provided by independent engineering firms, as well as by Horizon Power, the state-owned utility. The Corporation is taking all steps necessary to protect its interests in the facility and ensure all cash flows promised under the South Hedland PPA are realized. The South Hedland Power Station has been fully operational and able to meet FMG's requirements under the terms of the South Hedland PPA since July 2017.

TEC Hedland commenced proceedings in the Supreme Court of Western Australia on Dec. 4, 2017, to recover amounts invoiced under the South Hedland PPA.

L. Re-acquisition of Solomon Power Station

On Aug. 1, 2017, the Corporation received notice of FMG's intention to repurchase the Solomon Power Station from TEC Pipe Pty Ltd. ("TEC Pipe"), a wholly owned subsidiary of the Corporation, for approximately US$335 million. FMG completed its acquisition of the Solomon Power Station on Nov. 1, 2017, and TEC Pipe received US$325 million as consideration. FMG has held back the balance from the purchase price. It is the Corporation's view that this should not have been held back and the Corporation is taking action in the Supreme Court of Western Australia to recover all, or a significant portion of, this amount from FMG.

M. TransAlta Renewables' $260-Million Project Financing of New Brunswick Wind Assets and Early Redemption of Outstanding Debentures

On Oct. 2, 2017, TransAlta Renewables announced that its indirect majority-owned subsidiary, KHWLP, closed an approximate $260 million bond offering, secured by, among other things, a first ranking charge over all assets of KHWLP. The bonds are amortizing and bear interest at a rate of 4.454 per cent, payable quarterly, and mature on Nov. 30, 2033. A portion of the net proceeds was used to fund a portion of the construction costs for the 17.25 MW Kent Hills 3 wind project. The remaining proceeds were advanced to its subsidiary Canadian Hydro Developers, Inc. ("CHD") and to Natural Forces Technologies Inc., KHWLP's partner, which owns approximately 17 per cent of KHWLP. Proceeds of $31 million are classified as restricted cash as at Dec. 31, 2018, relating to the construction reserve account, and will be released upon certain conditions being met, which are expected to be finalized in Q1 2019.

At the same time, CHD, a wholly owned subsidiary of TransAlta Renewables, provided notice that it would be early redeeming all of its unsecured debentures. The debentures were scheduled to mature in June 2018. On Oct. 12, 2017, CHD redeemed the unsecured debentures for $201 million, which included the principal of $191 million, an early redemption premium of $6 million and accrued interest of $4 million. The $6 million early redemption premium was recognized in net interest expense for the year ended Dec. 31, 2017.

N. Series E and C Preferred Share Conversion Results and Dividend Rate Reset

On Sept. 17, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of its Series E Preferred Shares into Series F Preferred Shares. As a result, none of the Series E Preferred Shares were converted into Series F Preferred Shares on Sept. 30, 2017, and the dividend rate remains fixed for the subsequent five-year period. See Note 25 for further details.

On June 16, 2017, the Corporation announced that the minimum election notices received did not meet the requirements to give effect to the conversion of its Series C Preferred Shares into the Series D Preferred Shares. As a result, none of the Series C Preferred Shares were converted into Series D Preferred Shares on June 30, 2017, and the dividend remains fixed for the subsequent five-year period. See Note 25 for further details.

O. Alberta Off-Coal Agreement

On Nov. 24, 2016, the Corporation announced that it had entered into an agreement with the Government of Alberta (the "Government") on transition payments for the cessation of coal-fired emissions from the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation will receive annual cash payments of approximately $37 million, net to the Corporation, commencing in 2017 and terminating in 2030. 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. Other conditions include: maintaining prescribed spending on investment and investment-related activities in Alberta; maintaining a significant business presence in Alberta (including through the maintenance of prescribed employment levels); and maintaining spending on programs and initiatives to support the communities surrounding the plants, the employees of the Corporation negatively impacted by the phase-out of coal generation and fulfilling all obligations to affected employees. The affected plants are not, however, precluded from generating electricity at any time by any method, other than the combustion of coal.

The Corporation also entered into a Memorandum of Understanding with the Government to collaborate and co-operate in the development of a policy framework to facilitate coal-to-gas fired conversions and renewable electricity development, and ensure existing generation is able to effectively participate in a future capacity market to be developed for the Province of Alberta.

P. Force Majeure Relief - Keephills 1

Keephills 1 tripped off-line on March 5, 2013, due to a suspected winding failure within the generator. After extensive testing and analysis, it was determined that a full rewind of the generator stator was required. After completing the repairs, the unit returned to service on Oct. 6, 2013. The Corporation claimed force majeure relief on March 26, 2013. The buyer, ENMAX, disputed the claim of force majeure, which triggered the need for an arbitration hearing that took place in May 2016. On Nov. 18, 2016, the Corporation announced that the independent arbitration panel confirmed the Corporation's claim for force majeure relief. Accordingly, the Corporation reversed a provision of approximately $94 million in 2016. The buyer and the Balancing Pool are seeking to set the arbitration panel's decision aside in the Court of Queen's Bench of Alberta. This application is scheduled to be heard from Feb. 27, 2019 to Mar. 1, 2019.

Q. Poplar Creek Financing

On Dec. 7, 2016, the Corporation announced that its indirect wholly owned subsidiary, TAPC Holdings LP, which holds the Corporation's interest in the Poplar Creek cogeneration facility, completed the private placement of a $202.5 million aggregate principal amount of senior secured floating rate bonds. The bonds, which mature on Dec. 31, 2030, are secured by a first ranking charge over the equity interests of the issuer of such bonds. The bonds are amortizing and bear interest for each quarterly interest period at a rate per annum equal to the three-month Canadian Dollar Offered Rate in effect on the first day of such quarterly interest period plus 395 basis points.

R. Mississauga Cogeneration Facility NUG Contract

On Dec. 22, 2016, the Corporation announced it had signed the Non-Utility Generator Contract (the "NUG Contract") with the Ontario Independent Electricity System Operator (the "IESO") for its Mississauga cogeneration facility. The NUG Contract was effective on Jan. 1, 2017, and, in conjunction with the execution of the NUG Contract, the Corporation agreed to terminate, effective Dec. 31, 2016, the facility's existing contract with the Ontario Electricity Financial Corporation, which would have otherwise terminated in December 2018. In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. effective Dec. 31, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

The NUG Contract provided the Corporation with fixed monthly payments until Dec. 31, 2018, with no delivery obligations. Further details on the NUG Contract and its impact to these financial statements can be found in Note 9(C).

S. Wintering Hills Assets Held for Sale

The Corporation acquired its interest in Wintering Hills in 2015 in connection with the restructuring of the arrangements associated with its Poplar Creek cogeneration facility. At Dec. 31, 2016, the criteria for Wintering Hills to be classified as held for sale were met. The assets held for sale are measured at the lower of carrying amount and fair value less costs to sell. Accordingly, the Corporation recorded an impairment charge of $28 million in 2016, included in the Wind and Solar segment. Wintering Hills was sold on March 1, 2017, for net proceeds to the Corporation of $61 million.

T. Project Financing of a Quebec Wind Asset by TransAlta Renewables

On June 3, 2016, TransAlta Renewables' indirect wholly owned subsidiary, New Richmond Wind L.P. (the "NRWLP"), closed a bond offering of approximately $159 million, which is secured by a first ranking charge over all assets of the NRWLP. The bonds are amortizing and bear interest at a rate of 3.963 per cent, payable semi-annually, and mature on June 30, 2032.

U. Investment in, and Acquisition by, TransAlta Renewables of the Sarnia Cogeneration Plant, Le Nordais Wind Farm and Ragged Chute Hydro Facility (the "Canadian Assets")

On Jan. 6, 2016, TransAlta Renewables completed its investment in an economic interest based on the cash flows of the Corporation's Canadian Assets for a combined aggregate value of approximately $540 million. The Canadian Assets consist of approximately 611 MW of highly contracted power generation assets located in Ontario and Québec.

As consideration, TransAlta Renewables provided to the Corporation $173 million in cash, issued 15,640,583 common shares with an aggregate value of $152 million and issued a $215 million convertible unsecured subordinated debenture. On Nov. 9, 2017, TransAlta Renewables repaid the debentures early, for $218 million in total, comprised of principal of $215 million and accrued interest of $3 million. The convertible debenture was scheduled to mature on Dec. 31, 2020.

TransAlta Renewables funded the cash proceeds through the public issuance of 17,692,750 subscription receipts at a price of $9.75 per subscription receipt. Upon the closing of the transaction, each holder of subscription receipts received, for no additional consideration, one common share of TransAlta Renewables and a cash dividend equivalent payment of $0.07 for each subscription receipt held. As a result, TransAlta Renewables issued 17,692,750 common shares and paid a total dividend equivalent of $1 million. Share issuance costs amounted to $8 million, net of $2 million income tax recovery.

On Nov. 30, 2016, TransAlta Renewables acquired direct ownership of the Canadian Assets from the Corporation for a purchase price of $520 million by issuing a promissory note. At the same time, the Corporation's subsidiary redeemed the preferred shares that it had issued to TransAlta Renewables in January 2016 when TransAlta Renewables acquired an economic interest in the Canadian Assets as described above for $520 million. The two transactions were subject to a set-off arrangement and resulted in no cash payments. TransAlta Renewables also acquired working capital and certain capital spares totalling $19 million through the issuance of a non-interest bearing loan payable to the Corporation.

The acquisition of the Canadian Assets 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 Canadian Assets' assets and liabilities acquired were recognized at the book values previously recognized by TransAlta at Nov. 30, 2016, 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 $38 million in 2016.

5. Revenue

A. Disaggregation of Revenue

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

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues from contracts with customers	517	9	224	91	206	132	—	—	1,179
Revenue from leases[1]	68	—	—	68	27	7	—	—	170
Revenue from derivatives	(1)	115	4	—	(20)	—	67	—	165
Government incentives	—	—	—	—	16	—	—	—	16
Revenue from other[2]	328	318	4	6	53	17	—	(7)	719
Total revenue	912	442	232	165	282	156	67	(7)	2,249
Revenues from contracts with customers									
Timing of revenue recognition									
At a point in time	38	9	—	—	18	—	—	—	65
Over time	479	—	224	91	188	132	—	—	1,114
Total revenue from contracts with customers	517	9	224	91	206	132	—	—	1,179

(1) Total rental income, including contingent rent related to certain PPAs and other long-term contracts that meet the criteria of operating leases. 2017 - $247 million, 2016 - $221 million.
(2) Includes merchant revenue and other miscellaneous.

B. Contract Balances

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

Contract liabilities	
Dec. 31, 2017	62
IFRS 15 transition adjustment	17
Amounts transferred to revenue included in opening balance	(10)
Consideration received	13
Increases due to interest accrued and expensed during the period	6
Amounts transferred to payables	(1)
Dec. 31, 2018	**87**

Contract liabilities are primarily comprised of consideration received from the Corporation's Keephills Unit 3 joint operation partner for which the Corporation has a future obligation to transfer goods and services to the partner under the contract. Consideration received is dependent upon the Corporation's mine capital replacement plan and revenue is recognized as the Corporation satisfies its performance obligations under the contract of being available to deliver coal and the delivery of coal.

C. Remaining Performance Obligations

As required by the new revenue standard, the Corporation is required to disclose the aggregate amount of the transaction price allocated to remaining performance obligation (contract revenues that have not yet been recognized) for contracts in place at the end of the reporting period. The following disclosures exclude revenues related to contracts that qualify for the following practical expedients:

- The Corporation recognizes revenue from the contract in an amount that is equal to the amount invoiced where the amount invoiced represents the value to the customer of the service performed to date. Certain of the Corporation's contracts at some of its wind, hydro, gas and solar facilities, and within its commercial and industrial business, qualify

for this practical expedient. For these contracts, the Corporation is not required to disclose information about the remaining unsatisfied performance obligations.
- Contracts with an original expected duration of less than 12 months.

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

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

Canadian Coal
At Dec. 31, 2018, the Corporation has PPAs with the Balancing Pool for capacity and electricity from two of its coal plants, as dispatched, with contract end dates of Dec. 31, 2020. All generation produced is delivered to the customer. Certain sources of revenue under one PPA contract are accounted for as a lease, and are excluded from these disclosures. Pricing is comprised of multiple components, of both fixed and variable nature, consisting of a capacity payment based on a return of capital, availability payments (from or to the customer) based on the 30-day rolling average pool price and actual availability of the plant as compared to targeted availability specified in the PPAs, recovery of regulatory pass-through costs, and payments for delivery of energy based on the variable cost of producing the energy. Energy-related payments are variable depending on output from the plant, which is dependent upon market demand and the operational ability of the plant. Revenues are generally recognized over time, on a monthly basis. Future revenues that are based upon variable consideration are considered to be fully constrained and are excluded from these disclosures.

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

The Corporation has a contract at its Alberta coal mine that requires it to be available to deliver coal as required, and to provide byproduct disposal services for the plant. The duration of the contract is largely dependent upon the Corporation's coal-to-gas transition plans and decisions. Pricing terms are based on actual costs incurred to provide the coal, and will vary over the life of the contract. Revenue will be recognized on the basis of the costs incurred and based on volumes of coal delivered, which are variable and depend upon market demand for electricity, which is subject to factors outside of the Corporation's control. Accordingly, revenues related to remaining performance obligations associated with this component of the contract are excluded from these disclosures as they are variable and considered to be fully constrained. The customer also funds a portion of the required mine capital as part of the transaction price, which the Corporation has determined constitutes a significant financing component. Revenues are dependent upon the Corporation's mine capital replacement plan and the recoveries, along with the significant financing component, and are amortized into revenue as the Corporation satisfies its performance obligations of being available to deliver coal and the delivery of coal. The significant financing component of these revenues is excluded from these disclosures.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $330 million, of which the Corporation expects to recognize approximately $245 million in total over the next two fiscal years and on average, between approximately $7 million to $10 million annually thereafter for the duration of the contracts.

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

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

Canadian Gas
At Dec. 31, 2018, the Corporation has contracts with customers to deliver energy services from one of its gas plants in Ontario. The contracts all consist of a single performance obligation requiring the Corporation to stand ready to deliver electricity and steam. The following is a summary of the key terms:

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, These variable revenues under the contracts are considered to be fully constrained. Accordingly, these revenues are excluded from these disclosures. The Corporation expects to recognize revenue as it delivers electricity and steam until the completion of the contract in late 2022.

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

At Dec. 31, 2018, the Corporation has contracts with customers to deliver steam, hot water and chilled water from one of its other gas plants in Ontario, extending through 2023. Prices under these contracts are at fixed base amounts per gigajoule and are subject to escalation annually for both gas prices and inflation. The contracts include minimum annual take-or-pay volumes.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $25 million in total, of which the Corporation expects to be on average, between approximately $4 million to $6 million annually thereafter for the duration of the contracts.

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

Australian Gas
At Dec. 31, 2018, the Corporation has PPAs with customers to deliver electricity from its gas plants located in Australia. One contract is considered to be a lease and is excluded from these disclosures. The PPAs generally call for all available generation to be provided to customers. Pricing terms include fixed and variable price components for delivered electricity and fixed capacity payments. Prices may be subject to true-up adjustments for deviations from expected heat rates and are subject to various escalators to reflect inflation. Electricity delivered is ultimately dependent upon customer requirements, which is outside of the Corporation's control. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The contracts have durations that range from 2021 to 2042.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $2,280 million, of which the Corporation expects to recognize approximately $230 million in total over the next three fiscal years and on average, between approximately $80 million to $110 million annually thereafter for the duration of the contracts.

Wind and Solar
At Dec. 31, 2018, the Corporation had long-term contracts with customers to deliver electricity and the associated renewable energy credits from two wind farms located in Alberta and Minnesota, 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 and 2034. Electricity delivered is ultimately dependent upon the wind resource, which is outside of the Corporation's control. Amounts delivered, and therefore revenue recognized, in the future will vary. These variable revenues for electricity delivered are considered to be fully constrained, and will be recognized at a point in time as the performance obligation, the delivery of electricity, is satisfied. Accordingly, these revenues are excluded from these disclosures. The Corporation also has contracts to sell renewable energy certificates generated at merchant wind facilities and expects to recognize revenues as it delivers the renewable energy certificates to the purchaser over the remaining terms of the contracts, from 2019 through 2024.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $9 million, of which the Corporation expects to recognize between approximately $1 million to $2 million annually through to contract expiry.

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

Hydro
At Dec. 31, 2018, the Corporation has a PPA with the Balancing Pool to provide the capacity of 12 hydro plants throughout the province of Alberta. The capacity payment is fixed on an annual basis. As part of the PPA, the Corporation also has a financial obligation to the Balancing Pool determined on the basis of notional quantities of electricity delivered and the pool price for the period. The Corporation expects to recognize revenue as it makes capacity available to the customer until completion of the contract term at Dec. 31, 2020. The Corporation also has contracts for blackstart services at specific hydro plants and a contract with the Government of Alberta to manage water on the Bow River for flood and drought mitigation purposes, which all conclude within 2020.

Estimated future revenues related to the remaining performance obligations for these contracts as of Dec. 31, 2018, are approximately $130 million, which the Corporation expects to recognize over the next two fiscal years.

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

6. Expenses by Nature

Expenses classified by nature are as follows:

Year ended Dec. 31	**2018**		2017		2016	
	Fuel and purchased power	**Operations, maintenance and administration**	Fuel and purchased power	Operations, maintenance and administration	Fuel and purchased power	Operations, maintenance and administration
Fuel[1]	**656**	**–**	685	–	665	–
Coal inventory writedown (recovery)	**–**	**–**	–	–	(4)	–
Purchased power	**210**	**–**	162	–	143	–
Mine depreciation	**136**	**–**	73	–	63	–
Salaries and benefits[1]	**98**	**245**	96	248	96	249
Other operating expenses	**–**	**270**	–	269	–	240
Total	**1,100**	**515**	1,016	517	963	489

(1) $90 million in both 2017 and 2016 was reclassified from fuel to salaries and benefits to be consistent with the 2018 classification.

7. Asset Impairment Charges and Reversals

As part of the Corporation's monitoring controls, long-range forecasts are prepared for each CGU. The long-range forecast estimates are used to assess the significance of potential indicators of impairment and provide criteria to evaluate adverse changes in operations. The Corporation also considers the relationship between its market capitalization and its book value, among other factors, when reviewing for indicators of impairment. When indicators of impairment are present, the

Corporation estimates a recoverable amount for each CGU by calculating an approximate fair value less costs of disposal using discounted cash flow projections based on the Corporation's long-range forecasts. The valuations used are subject to measurement uncertainty based on assumptions and inputs to the Corporation's long-range forecast, including changes to fuel costs, operating costs, capital expenditures, external power prices and useful lives of the assets extending to the last planned asset retirement in 2073.

A. Alberta Merchant CGU

During 2018, 2017 and 2016, uncertainty continued to exist within the province of Alberta regarding the Government's Climate Leadership Plan, the future design parameters of the Alberta electricity market, and federal policies on the carbon levy and greenhouse gas ("GHG") emissions. Economic conditions also contributed to continued oversupply conditions and depressed market prices throughout 2015 to 2017. The Corporation assessed whether these factors, and events arising during the latter part of 2016, which are more fully discussed below, presented an indicator of impairment for its Alberta Merchant CGU. In consideration of the composition of this CGU, the Corporation determined that no indicators of impairment were present with respect to the Alberta Merchant CGU. Due to this determination, the Corporation did not perform an in-depth impairment analysis for any of these years, but for all years, a sensitivity analysis associated with these factors was performed to confirm the continued existence of adequate excess of estimated recoverable amount over book value. This analysis of the Alberta Merchant CGU continued to demonstrate a substantial cushion at the Alberta Merchant CGU in each of 2018, 2017 and 2016, due to the Corporation's large merchant renewable fleet in the province.

I. 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 where significant cushion exists. 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(D)). In connection with these acquisitions, the assets were fair valued using discount rates that average approximately 7 per cent. Accordingly, the Corporation has recorded an impairment charge of $12 million using the valuation in the agreement as the indicator of fair value less cost of disposal in 2018. The impairment charge had an $11 million impact on PP&E and a $1 million impact on intangible assets (See Note 17 and 19).

II. 2017

Sundance Unit 1

In the second quarter of 2017, the Corporation recognized an impairment charge on Sundance Unit 1 in the amount of $20 million, due to the Corporation's decision to early retire Sundance Unit 1. Previously, the Corporation had expected Sundance Unit 1 to operate in the merchant market in 2018 and 2019 and therefore remain within the Alberta Merchant CGU where significant cushion exists. The impairment assessment was based on value in use and included the estimated future cash flows expected to be derived from the Unit until its retirement on Jan. 1, 2018. Discounting did not have a material impact.

No separate stand-alone impairment test was required for Sundance Unit 2, as mothballing the Unit maintained the Corporation's flexibility to operate the Unit as part of the Corporation's Alberta Merchant CGU to 2021.

III. 2016

Wintering Hills

On Jan. 26, 2017, the Corporation announced the sale of its 51 per cent interest in the Wintering Hills merchant wind facility for approximately $61 million (see Note 4(S)). In connection with this sale, the Wintering Hills assets were accounted for as held for sale at Dec. 31, 2016. As required, the Corporation assessed the assets for impairment prior to classifying them as held for sale. Accordingly, the Corporation has recorded an impairment charge of $28 million using the purchase price in the sale agreement as the indicator of fair value less cost of disposal in 2016.

B. Project Development Costs

During 2018, the Corporation wrote off $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 Fort Saskatchewan cogeneration facility and the Poplar Creek cogeneration facility are as follows:

As at Dec. 31	2018		2017	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**30**	**29**	68	66
Second to fifth years inclusive	**80**	**74**	110	82
More than five years	**140**	**112**	140	126
	250	**215**	318	274
Less: unearned finance lease income	**35**	**—**	44	—
Total finance lease receivables	**215**	**215**	274	274

Included in the Consolidated Statements of Financial Position as:	2018	2017
Current portion of finance lease receivables (Note 13)	**24**	59
Long-term portion of finance lease receivables	**191**	215
	215	274

9. Net Other Operating Expense (Income)

Net other operating expense (income) includes the following:

Year ended Dec. 31	2018	2017	2016
Alberta Off-Coal Agreement	**(40)**	(40)	—
Termination of the Sundance B and C PPAs	**(157)**	—	—
Mississauga cogeneration facility NUG Contract	**—**	(9)	(191)
Insurance recoveries	**(7)**	—	(3)
Restructuring provision	**—**	—	1
Net other operating expense (income)	**(204)**	(49)	(193)

A. Alberta Off-Coal Agreement

The Corporation receives payments from the Government of Alberta for the cessation of coal-fired emissions from its interest in the Keephills 3, Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

Under the terms of the OCA, the Corporation receives annual cash payments on or before July 31 of approximately $40 million ($37 million, net to the Corporation), commencing Jan. 1, 2017, and terminating at the end of 2030. The Corporation recognizes the off-coal payments evenly throughout the year. Receipt of the payments is subject to certain terms and conditions. The OCA's main condition is the cessation of all coal-fired emissions on or before Dec. 31, 2030. The affected plants are not, however, precluded from generating electricity at any time by any method, other than generation resulting in coal-fired emissions after Dec. 31, 2020. In July 2018, the Corporation obtained financing against the OCA payments (See Note 4(O) and 22).

B. Termination of the Sundance B and C PPAs

On Sept. 18, 2017, the Corporation received formal notice from the Balancing Pool of the termination of the Sundance B and C PPAs effective March 31, 2018, and received a termination payment of $157 million during the first quarter of 2018. See Note 4(J) for further details.

C. Mississauga Cogeneration Facility Contract

2016

On Dec. 22, 2016, the Corporation announced it had signed a NUG Contract with the IESO for its Mississauga cogeneration facility. The contract was effective on Jan. 1, 2017. The Corporation has agreed to terminate the prior contract with the IESO early, which would have otherwise terminated in December 2018.

As a result of the NUG Contract, the Corporation recognized a pre-tax gain of approximately $191 million. The predominant components of the gain relate to recognition of a one-time discounted revenue amount of approximately $207 million, offset by onerous contract expenses and other termination charges totalling approximately $16 million. The Corporation also recognized $46 million in accelerated depreciation resulting from the change in useful life of the asset. The Corporation released and recognized in earnings unrealized pre-tax net losses of $14 million from AOCI due to cash flow hedges de-designated for accounting purposes.

2017

During the fourth quarter of 2017, the Corporation renegotiated the facility's land lease agreement at a lower cost than previously estimated in 2016, and accordingly, recognized a gain of $9 million.

2018

In December 2018, TransAlta exercised its option to terminate its agreement with Boeing Canada Inc. effective Jan. 1, 2021. TransAlta is required to remove the plant and restore the site within the three-year time frame.

D. Insurance Recoveries

During 2018, the Corporation received $7 million in insurance recoveries, of which $6 million related insurance proceeds for the tower fire at Wyoming Wind and a $1 million claim related to equipment repairs within Canadian Coal. There were no insurance recoveries in 2017.

During 2016, the Corporation received $3 million in insurance recoveries, of which $2 million related to business interruption insurance claims and $1 million related to claims for replacement and refurbishment of equipment for certain wind facilities.

10. Net Interest Expense

The components of net interest expense are as follows:

Year ended Dec. 31	2018	2017	2016
Interest on debt	**184**	218	218
Interest income	**(11)**	(7)	(2)
Capitalized interest (Note 17)	**(2)**	(9)	(16)
Loss on redemption of bonds (Note 22)	**24**	6	1
Interest on finance lease obligations	**3**	3	3
Credit facility fees, bank charges and other interest	**13**	18	19
Keephills 1 outage interest (reversals) (Note 4(P))	**—**	—	(10)
Other[1]	**15**	(3)	(4)
Accretion of provisions (Note 21)	**24**	21	20
Net interest expense	**250**	247	229

(1) During 2018, approximately $5 million of costs were expensed due to project-level financing that is no longer practicable and approximately $7 million for the significant financing component required under IFRS 15 (see Note 3).

11. Income Taxes

A. Consolidated Statements of Earnings

I. Rate Reconciliations

Year ended Dec. 31	2018	2017	2016
Earnings before income taxes	**(96)**	(54)	314
Net earnings attributable to non-controlling interests not subject to tax	**(19)**	(35)	(109)
Adjusted earnings before income taxes	**(115)**	(89)	205
Statutory Canadian federal and provincial income tax rate (%)	**26.8**	26.8	26.7
Expected income tax expense (recovery)	**(31)**	(24)	55
Increase (decrease) in income taxes resulting from:			
Lower effective foreign tax rates	**(3)**	(11)	(16)
Deferred income tax expense related to temporary difference on investment in subsidiary	**—**	—	11
Writedown (reversal of writedown) of deferred income tax assets	**27**	(15)	(10)
Statutory and other rate differences	**—**	110	1
Other	**1**	4	(3)
Income tax expense (recovery)	**(6)**	64	38
Effective tax rate (%)	**5**	72	19

II. Components of Income Tax Expense

The components of income tax expense are as follows:

Year ended Dec. 31	2018	2017	2016
Current income tax expense[1]	**28**	79	23
Adjustments in respect of deferred income tax of previous years	**—**	—	(3)
Deferred income tax expense (recovery) related to the origination and reversal of temporary differences	**(61)**	(110)	16
Deferred income tax expense related to temporary difference on investment in subsidiary[2]	**—**	—	11
Deferred income tax expense resulting from changes in tax rates or laws[3]	**—**	110	1
Deferred income tax expense (recovery) arising from the writedown (reversal of writedown) of deferred income tax assets[4]	**27**	(15)	(10)
Income tax expense (recovery)	**(6)**	64	38

Year ended Dec. 31	2018	2017	2016
Current income tax expense	**28**	79	23
Deferred income tax expense (recovery)	**(34)**	(15)	15
Income tax expense (recovery)	**(6)**	64	38

(1) During 2017, the Corporation recognized current tax expense of $56 million due to the disposition of the Solomon Power Station on Nov. 1, 2017.
(2) In 2016, reorganizations of certain TransAlta subsidiaries were completed in connection with the New Richmond project financing and the disposition of the Canadian Assets to TransAlta Renewables. The reorganizations resulted in the recognition of deferred tax liabilities of $3 million and $8 million, respectively. The deferred tax liabilities had not been recognized previously, as prior to the reorganizations, the taxable temporary differences were not expected to reverse in the foreseeable future.
(3) On Dec. 22, 2017, the US government enacted H.R.1, originally known as the Tax Cuts and Jobs Act, *which includes legislation to decrease its federal corporate income tax rate from 35 per cent to 21 per cent. The Corporation's net deferred tax liability associated with its directly owned US operations is made up of a deferred tax asset and a deferred tax liability that net to $6 million. The decrease in the US federal corporate income tax rate resulted in a decrease to the deferred tax asset of $104 million, all of which is recorded as deferred tax expense in the Consolidated Statement of Earnings, offset by a decrease to the deferred tax liability of $110 million, of which $1 million is recorded as deferred tax expense in the Consolidated Statement of Earnings with an offsetting $111 million deferred tax recovery recorded in the Consolidated Statement of Other Comprehensive Income. 2016 relates to the impact of increase in the New Brunswick corporate income tax rate from 12 per cent to 14 per cent, enacted Feb. 3, 2016.*
(4) During the year ended Dec. 31, 2018, the Corporation recorded a writedown of deferred income tax assets of $27 million (2017 - $15 million writedown reversal, 2016 - $10 million writedown reversal). The deferred income tax assets relate mainly to the tax benefits of losses associated with the Corporation's directly owned US operations. The Corporation had written these assets off as it was no longer considered probable that sufficient future taxable income would be available from the Corporation's directly owned US operations to utilize the underlying tax losses, due to reduced price growth expectations. Net operating losses expire between 2021 and 2037 for losses generated prior to 2018.

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	2018	2017	2016
Income tax expense (recovery) related to:			
Net impact related to cash flow hedges	**(12)**	(108)	51
Net impact related to net investment hedges	**—**	(7)	16
Net actuarial gains (losses)	**5**	(4)	4
Income tax expense reported in equity	**(7)**	(119)	71

C. Consolidated Statements of Financial Position

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

As at Dec. 31	2018	2017
Net operating loss carryforwards	**547**	541
Future decommissioning and restoration costs	**113**	117
Property, plant and equipment	**(896)**	(1,009)
Risk management assets and liabilities, net	**(145)**	(160)
Employee future benefits and compensation plans	**68**	74
Interest deductible in future periods	**48**	50
Foreign exchange differences on US-denominated debt	**35**	42
Deferred coal revenues	**23**	16
Other deductible temporary differences	**—**	22
Net deferred income tax liability, before writedown of deferred income tax assets	**(207)**	(307)
Writedown of deferred income tax assets	**(266)**	(218)
Net deferred income tax liability, after writedown of deferred income tax assets	**(473)**	(525)

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

As at Dec. 31	2018	2017
Deferred income tax assets(1)	**28**	24
Deferred income tax liabilities	**(501)**	(549)
Net deferred income tax liability	**(473)**	(525)

(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, 2018, the Corporation had recognized a net liability of nil (2017 - $4 million) related to uncertain tax positions.

12. Non-Controlling Interests

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

Subsidiary/Operation	Non-controlling interest as at Dec. 31, 2018
TransAlta Cogeneration L.P.	49.99% - Canadian Power Holdings Inc.
TransAlta Renewables	39.1% - Public shareholders
Kent Hills Wind LP(1)	17% - Natural Forces Technologies Inc.

(1) Owned by TransAlta Renewables.

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

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

A. TransAlta Renewables

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

The South Hedland Power Station achieved commercial operation on July 28, 2017. On Aug. 1, 2017, the Corporation converted its 26.1 million Class B shares held in TransAlta Renewables into 26.4 million common shares of TransAlta Renewables. At that time, the Corporation's equity participation percentage in TransAlta Renewables increased to 64 per cent from 59.8 per cent. The Class B shares were converted at a ratio greater than 1:1 because the construction and commissioning costs for the project were below the referenced costs agreed to with TransAlta Renewables.

On May 31, 2018, TransAlta Renewables implemented a dividend reinvestment plan ("DRIP") for Canadian holders of common shares of TransAlta Renewables. Commencing with the dividend paid on July 31, 2018, eligible shareholders may elect to automatically reinvest monthly dividends into additional common shares of the Corporation.

As a result of the conversion of Class B shares, the DRIP and the transactions described in Note 4, the Corporation's share of ownership and equity participation in TransAlta Renewables has fluctuated since its formation as follows:

Period	Ownership and voting rights percentage	Equity participation percentage
April 29, 2014 to May 6, 2015	70.3	70.3
May 7, 2015 to Nov. 25, 2015	76.1	72.8
Nov. 26, 2015 to Jan. 5, 2016	66.6	62.0
Jan. 6, 2016 to July 31, 2017	64.0	59.8
Aug. 1, 2017 to June 21, 2018	64.0	64.0
June 22, 2018 to July 30, 2018	61.1	61.1
July 31, 2018 to Nov. 29, 2018	61.0	61.0
Nov. 30, 2018 to Dec. 31, 2018	60.9	60.9

Year ended Dec. 31	2018	2017	2016
Revenues	**462**	459	259
Net earnings	**241**	13	1
Total comprehensive income	**281**	(24)	40
Amounts attributable to the non-controlling interests:			
Net earnings	**94**	11	2
Total comprehensive income	**110**	—	18
Distributions paid to non-controlling interests	**79**	85	83

As at Dec. 31	2018	2017
Current assets	**250**	145
Long-term assets	**3,497**	3,483
Current liabilities	**(159)**	(356)
Long-term liabilities	**(1,192)**	(1,075)
Total equity	**(2,396)**	(2,197)
Equity attributable to non-controlling interests	**(961)**	(812)
Non-controlling interests' share (per cent)	**39.1**	36.0

B. TA Cogen

Year ended Dec. 31	2018	2017	2016
Results of operations			
Revenues	**185**	175	274
Net earnings	**29**	61	211
Total comprehensive income	**29**	61	258
Amounts attributable to the non-controlling interest:			
Net earnings	**14**	31	105
Total comprehensive income	**14**	31	128
Distributions paid to Canadian Power Holdings Inc.	**86**	87	68

As at Dec. 31	2018	2017
Current assets	**82**	193
Long-term assets	**354**	404
Current liabilities	**(54)**	(73)
Long-term liabilities	**(28)**	(26)
Total equity	**(354)**	(498)
Equity attributable to Canadian Power Holdings Inc.	**(176)**	(247)
Non-controlling interest share (per cent)	**49.99**	49.99

13. Trade and Other Receivables

As at Dec. 31	2018	2017
Trade accounts receivable	**597**	693
Mississauga recontracting receivable	**—**	108
Net trade receivables	**597**	801
Promissory note receivable(1)	**25**	—
Collateral paid (Note 15)	**105**	67
Current portion of finance lease receivables (Note 8)	**24**	59
Current portion of loan receivable (Note 20)	**—**	5
Income taxes receivables	**5**	1
Trade and other receivables	**756**	933

(1) The promissory note receivable relates to funding provided for the Antrim wind development project (see Note 4(C) for further details).

14. Financial Instruments

A. Financial Assets and Liabilities – Classification and Measurement

Financial assets and financial liabilities are measured on an ongoing basis at cost, fair value or amortized cost (see Note 2 (C)). The following table outlines the carrying amounts and classifications of the financial assets and liabilities:

Carrying value as at Dec. 31, 2018

	Derivatives used for hedging	Derivatives held for trading (FVTPL)	Amortized cost	Other financial assets (FVTPL)	Total
Financial assets					
Cash and cash equivalents(1)	—	—	89	—	89
Restricted cash	—	—	66	—	66
Trade and other receivables	—	—	731	25	756
Long-term portion of finance lease receivables	—	—	191	—	191
Risk management assets					
Current	60	86	—	—	146
Long-term	629	33	—	—	662
Other assets	—	—	37	15	52
Financial liabilities					
Accounts payable and accrued liabilities	—	—	497	—	497
Dividends payable	—	—	58	—	58
Risk management liabilities					
Current	1	89	—	—	90
Long-term	1	40	—	—	41
Credit facilities, long-term debt and finance lease obligations(2)	—	—	3,267	—	3,267

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

Carrying value as at Dec. 31, 2017

	Derivatives used for hedging	Derivatives classified as held for trading	Loans and receivables	Other financial liabilities	Total
Financial assets					
Cash and cash equivalents(1)	—	—	314	—	314
Restricted cash	—	—	30	—	30
Trade and other receivables	—	—	933	—	933
Long-term portion of finance lease receivables	—	—	215	—	215
Risk management assets					
Current	82	137	—	—	219
Long-term	638	46	—	—	684
Other assets	—	—	33	—	33
Financial liabilities					
Accounts payable and accrued liabilities	—	—	—	595	595
Dividends payable	—	—	—	34	34
Risk management liabilities					
Current	8	93	—	—	101
Long-term	2	38	—	—	40
Credit facilities, long-term debt and finance lease obligations(2)	—	—	—	3,707	3,707

(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 regression or extrapolation formulas, where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets, and implied volatilities for options.

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 the Black-Scholes, mark-to-forecast and historical bootstrap models with inputs that are 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 prices.

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

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

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

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

As at Dec. 31	**2018**		2017	
Description	**Base fair value**	**Sensitivity**	Base fair value	Sensitivity
Long-term power sale - US	**801**	+116 -116	853	+130 -130
Long-term power sale - Alberta	**4**	+1 -1	(1)	+2 -2
Unit contingent power purchases	**18**	+4 -4	44	+7 -9
Structured products - Eastern US	**6**	+5 -5	17	+8 -7
Long-term wind energy sale - Eastern US	**(39)**	+21 -21	—	—
Others	**4**	+3 -3	5	+9 -9

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 2020, market forward power prices are not readily observable. For these periods, fundamental-based forecasts and market indications have been used to determine proxies for base, high and low power price scenarios. The base price forecast has been developed by using a fundamental-based forecast (the provider is an independent and widely accepted industry expert for scenario and planning views). Prior to the second quarter of 2018, the base price forecast was developed using an additional independent industry forecast. Forward power price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2018, are US$20-US$35 (Dec. 31, 2017 - US$25-US$34). The sensitivity analysis has been prepared using the Corporation's assessment that a US$6 (Dec. 31, 2017 - US$6) price increase or decrease in the forward power prices is a reasonably possible change.

The contract is denominated in US dollars. With the strengthening of the US dollar relative to the Canadian dollar from Dec. 31, 2017 to Dec. 31, 2018, the base fair value and the sensitivity values have increased by approximately $62 million and $9 million, respectively.

ii. Long-Term Power Sale - Alberta

The Corporation has a long-term 12.5 MW fixed price power sale contract (monthly shaped) in the Alberta market through December 2024. The contract is accounted for as FVTPL.

For periods beyond 2023, market forward power prices are not readily observable. For these periods, fundamental-based price forecasts and market indications have been used as proxies to determine base, high and low power price scenarios. The base scenario uses the most recent price view from an independent external forecasting service that is accepted within industry as an expert in the Alberta market. Forward power prices per MWh used in determining the Level III base fair value at Dec. 31, 2018, are $40 (Dec. 31, 2017 - $63 - $67). The sensitivity analysis has been prepared using the Corporation's assessment that a 20 per cent increase or decrease in the forward power prices is a reasonably possible change.

iii. Unit Contingent Power Purchases

Under the unit contingent power purchase agreements, the Corporation has agreed to purchase power contingent upon the actual generation of specific units owned and operated by third parties. Under these types of agreements, the purchaser pays the supplier an agreed upon fixed price per MWh of output multiplied by the pro rata share of actual unit production (nil if a plant outage occurs). The contracts are accounted for as FVTPL.

The key unobservable inputs used in the valuations are delivered volume expectations and hourly shapes of production. Hourly shaping of the production will result in realized prices that may be at a discount (or premium) relative to the average settled power price. Reasonably possible alternative inputs were used to determine sensitivity on the fair value measurements.

This analysis is based on historical production data of the generation units for available history. Price and volumetric discount ranges per MWh used in the Level III base fair value measurement at Dec. 31, 2018, are nil (Dec. 31, 2017 - nil) and 2.2 per cent to 16.9 per cent (Dec. 31, 2017 – 2.2 per cent to 2.8 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in price discount ranges of approximately 1.1 per cent to 1.9 per cent (Dec. 31, 2017 - 1.1 per cent to 1.9 per cent) and a change in volumetric discount rates of approximately 8.6 per cent to 27.3 per cent (Dec. 31, 2017 - 7.8 per cent and 10.5 per cent), which approximate one standard deviation for each input.

iv. Structured Products - Eastern US

The Corporation has fixed priced power and heat rate contracts in the eastern United States. Under the fixed priced power contracts, the Corporation has agreed to buy or sell power at non-liquid locations or during non-standard hours. The Corporation has also bought and sold heat rate contracts at both liquid and non-liquid locations. Under a heat rate contract, the buyer has the right to purchase power at times when the market heat rate is higher than the contractual heat rate.

The key unobservable inputs in the valuation of the fixed priced power contracts are market forward spreads and non-standard shape factors. A historical regression analysis has been performed to model the spreads between non-liquid and liquid hubs. The non-standard shape factors have been determined using the historical data. Basis relationship and non-standard shape factors used in the Level III base fair value measurement at Dec. 31, 2018, are 75 per cent to 109 per cent and 63 per cent to 104 per cent (Dec. 31, 2017 – 75 per cent to 159 per cent and 71 per cent to 88 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in market forward spreads of approximately 4 per cent to 7 per cent (Dec. 31, 2017 - 7 per cent) and a change in non-standard shape factors of approximately 4 per cent to 9 per cent (Dec. 31, 2017 - 6 per cent), which approximate one standard deviation for each input.

The key unobservable inputs in the valuation of the heat rate contracts are implied volatilities and correlations. Implied volatilities and correlations used in the Level III base fair value measurement at Dec. 31, 2018, are 25 per cent to 84 per cent and 70 per cent (Dec. 31, 2017 – 18 per cent to 54 per cent and 70 per cent), respectively. The sensitivity analysis has been prepared using the Corporation's assessment of a reasonably possible change in implied volatilities ranges and correlations of approximately 37 per cent to 49 per cent and 30 per cent, respectively (2017 - 27 per cent to 32 per cent and 10 per cent, respectively).

v. Long-Term Wind Energy Sale - Eastern US

In relation to the acquisition of Big Level (See Note 4(C)), 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 is expected to occur in the second half of 2019, with the contract extending for 15 years after commercial operation. The contract is accounted for at fair value through profit or loss.

The key unobservable inputs used in the valuation of the contract are expected proxy generation volumes and forward prices for power and RECs beyond 2023 and 2022, respectively. Forward power and REC price ranges per MWh used in determining the Level III base fair value at Dec. 31, 2018, are US$42-US$68 and US$7-US$8, respectively. The sensitivity analysis has been prepared using the Corporation's assessment that a change in expected proxy generation volumes of 10 per cent, a change in energy prices of US$6 and a change in REC prices of US$1 as reasonably possible changes.

II. Commodity Risk Management Assets and Liabilities

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

Commodity risk management assets and liabilities classified by fair value levels as at Dec. 31, 2018, are as follows: Level I - $3 million net asset (Dec. 31, 2017 - $1 million net liability), Level II - $19 million net liability (Dec. 31, 2017 - $42 million net liability) and Level III - $695 million net asset (Dec. 31, 2017 - $771 million net asset).

Significant changes in commodity net risk management assets (liabilities) during the year ended Dec. 31, 2018, are primarily attributable to the settlement of contracts, partially offset by favourable 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, 2018 and 2017, respectively:

	Year ended Dec. 31, 2018			Year ended Dec. 31, 2017		
	Hedge	**Non-hedge**	**Total**	Hedge	Non-hedge	Total
Opening balance	**719**	**52**	**771**	726	32	758
Changes attributable to:						
Market price changes on existing contracts	**(7)**	**(9)**	**(16)**	100	(2)	98
Market price changes on new contracts	**—**	**4**	**4**	—	33	33
Contracts settled	**(90)**	**(42)**	**(132)**	(57)	(10)	(67)
Change in foreign exchange rates	**67**	**5**	**72**	(50)	(2)	(52)
Transfers into (out of) Level III	**—**	**(4)**	**(4)**	—	1	1
Net risk management assets at end of period	**689**	**6**	**695**	719	52	771
Additional Level III information:						
Gains recognized in other comprehensive income	**60**	**—**	**60**	50	—	50
Total gains included in earnings before income taxes	**90**	**—**	**90**	57	29	86
Unrealized gains (losses) included in earnings before income taxes relating to net assets held at period end	**—**	**(42)**	**(42)**	—	19	19

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 $2 million as at Dec. 31, 2018 (Dec. 31, 2017 - $34 million net asset) are classified as Level II fair value measurements. The significant changes in other net risk management assets during the year ended Dec. 31, 2018, are primarily attributable to the settlement of contracts.

IV. Other Financial Assets and Liabilities

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

	Fair value(1)				**Total carrying**
	Level I	**Level II**	**Level III**	**Total**	**value(1)**
Long-term debt - Dec. 31, 2018	**—**	**3,181**	**—**	**3,181**	**3,204**
Long-term debt - Dec. 31, 2017	—	3,708	—	3,708	3,638

(1) Includes current portion.

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

The carrying amount of other short-term financial assets and liabilities (cash and cash equivalents, trade accounts receivable, collateral paid, accounts payable and accrued liabilities, collateral received and dividends payable) approximates fair value due to the liquid nature of the asset or liability. The fair values of the loan receivable (see Note 20) 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 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	**2018**	2017	2016
Unamortized net gain at beginning of year	**105**	148	202
New inception gains (losses)	**(14)**	12	10
Change in foreign exchange rates	**5**	(7)	(4)
Amortization recorded in net earnings during the year	**(47)**	(48)	(60)
Unamortized net gain at end of year	**49**	105	148

15. Risk Management Activities

A. Risk Management Strategy

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

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

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

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

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

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

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

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

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

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

B. Net Risk Management Assets and Liabilities

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

As at Dec. 31, 2018

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	**59**	**—**	**59**
Long-term	**628**	**(8)**	**620**
Net commodity risk management assets	**687**	**(8)**	**679**
Other			
Current	**—**	**(3)**	**(3)**
Long-term	**—**	**1**	**1**
Net other risk management assets (liabilities)	**—**	**(2)**	**(2)**
Total net risk management assets (liabilities)	**687**	**(10)**	**677**

As at Dec. 31, 2017

	Cash flow hedges	**Not designated as a hedge**	**Total**
Commodity risk management			
Current	74	7	81
Long-term	636	11	647
Net commodity risk management assets	710	18	728
Other			
Current	—	37	37
Long-term	—	(3)	(3)
Net other risk management assets (liabilities)	—	34	34
Total net risk management assets (liabilities)	710	52	762

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	2018				2017			
	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	**210**	**666**	**(121)**	**(50)**	281	637	(159)	(38)
Gross amounts set-off	**—**	**—**	**—**	**—**	(43)	—	43	—
Net amounts as presented in the Consolidated Statements of Financial Position	**210**	**666**	**(121)**	**(50)**	238	637	(116)	(38)

C. Nature and Extent of Risks Arising from Financial Instruments

I. Market Risk

a. Commodity Price Risk Management

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

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

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

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

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

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

i. Commodity Price Risk Management – Proprietary Trading

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

In compliance with the Commodity Exposure Management Policy, proprietary trading activities are subject to limits and controls, including Value at Risk ("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, 2018, associated with the Corporation's proprietary trading activities was $2 million (2017 - $5 million, 2016 - $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, 2018, associated with the Corporation's commodity derivative instruments used in generation hedging activities was $18 million (2017 - $16 million, 2016 - $19 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, 2018, associated with these transactions was $13 million (2017 - $5 million, 2016 - $7 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	**2018**		2017	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**2,128**	**—**	1,997	44

During 2018, unrealized pre-tax gains of $4 million (2017 - $2 million, 2016 - $0 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	**2018**		2017	
Type (thousands)	**Notional amount sold**	**Notional amount purchased**	Notional amount sold	Notional amount purchased
Electricity *(MWh)*	**58,885**	**37,023**	14,688	7,348
Natural gas *(GJ)*	**80,413**	**110,488**	74,195	103,805
Transmission *(MWh)*	**29**	**11,163**	1	3,455
Emissions *(tonnes)*	**3,134**	**2,948**	516	717

b. Interest Rate Risk Management

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

The Corporation's credit facility and the Poplar Creek non-recourse bond are the only debt instruments subject to floating interest rates, which represents 14 per cent of the Corporation's debt as at Dec. 31, 2018 (2017 - 6 per cent).

Interest rate risk is managed with the use of derivatives. No derivatives related to interest rate risk were outstanding as at Dec. 31, 2018, 2017 or 2016.

c. Currency Rate Risk
The Corporation has exposure to various currencies, such as the US dollar, the Japanese yen and the Australian dollar ("AUD"), 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.
- Designating foreign currency debt as a hedge of the net investment in foreign operations to mitigate the risk due to fluctuating exchange rates related to certain foreign subsidiaries.

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

The Corporation's hedges of its net investment in foreign operations were comprised of US-dollar-denominated long-term debt with a face value of US$400 million (2017 - US$480 million). During 2016, the Corporation de-designated its foreign currency forward contracts from its net investment hedges. The cumulative unrealized losses on these contracts are deferred in AOCI until the disposal of the related foreign operation.

ii. Cash Flow Hedges
The Corporation had no significant foreign currency cash flow hedges outstanding at Dec. 31, 2018 or 2017.

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

In order to mitigate some of the risk that is attributable to non-controlling interests, the Corporation entered into foreign currency contracts with third parties to the extent of the non-controlling interest percentage of the expected cash flow over five years to June 30, 2020. Hedge accounting was not applied to these foreign currency contracts. In early 2017, the Corporation revised its hedging strategies related to cash flows from its foreign operations. These foreign currency contracts became part of the Corporation's revised strategy, as opposed to a separate hedge program.

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

As at Dec. 31	**2018**			2017		
Notional amount sold	**Notional amount purchased**	**Fair value asset (liability)**	**Maturity**	Notional amount purchased	Fair value asset (liability)	Maturity
Foreign exchange forward contracts - foreign-denominated receipts/expenditures						
AUD218	**CAD205**	**(5)**	**2019-2022**	CAD157	(9)	2018-2021
USD164	**CAD214**	**(7)**	**2019-2022**	CAD104	11	2018-2021
Foreign exchange forward contracts - foreign-denominated debt						
CAD124	**USD100**	**10**	**2022**	USD230	(4)	2018
Cross currency swaps - foreign-denominated debt						
—	—	—		USD270	35	2018

During the first quarter of 2017, the Corporation discontinued hedge accounting for certain foreign currency cash flow hedges on US$690 million of debt. Changes in the risk management assets and liabilities related to these discontinued hedge positions have been reflected within net earnings prospectively.

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 four cent (2017 and 2016 - 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	**2018**		2017		2016	
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	**(13)**	**—**	(5)	—	(5)	—
AUD	**(7)**	**—**	(7)	—	(7)	—
Total	**(20)**	**—**	(12)	—	(12)	—

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

II. Credit Risk

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

The Corporation uses external credit ratings, as well as internal ratings in circumstances where external ratings are not available, to establish credit limits for customers and counterparties. The following table outlines the Corporation's maximum exposure to credit risk without taking into account collateral held, including the distribution of credit ratings, as at Dec. 31, 2018:

	Investment grade *(Per cent)*	**Non-investment grade** *(Per cent)*	**Total** *(Per cent)*	**Total amount**
Trade and other receivables[1]	86	14	**100**	**731**
Long-term finance lease receivables	100	—	**100**	**191**
Risk management assets[1]	99	1	**100**	**808**
Loans and notes receivable[2]	—	100	**100**	**77**
Total				**1,807**

(1) Letters of credit and cash and cash equivalents are the primary types of collateral held as security related to these amounts.
(2) Includes the promissory note receivable for $25 million (see Note 13), the loan receivable of $37 million and the note receivable for $15 million (see Note 20). The counterparties have no external credit ratings.

An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on historical rates of default by segment of trade receivables as well as forward-looking credit ratings and forecasted default rates. In addition to the calculation of expected credit losses, TransAlta monitors key forward looking information as potential indicators that historical bad debt percentages, forward-looking S&P credit ratings and forecasted default rates would no longer be representative of future expected credit losses. The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. TransAlta evaluates the concentration of risk with respect to trade receivables as low, as its customers are located in several jurisdictions and industries. The Corporation did not have significant expected credit losses as at Dec. 31, 2018.

The Corporation's maximum exposure to credit risk at Dec. 31, 2018, 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, 2018, was $13 million (2017 - $40 million).

III. Liquidity Risk

Liquidity risk relates to the Corporation's ability to access capital to be used for proprietary trading activities, commodity hedging, capital projects, debt refinancing and general corporate purposes. In December 2015, Moody's downgraded the senior unsecured rating on TransAlta's US bonds one notch from Baa3 to Ba1. As at Dec. 31, 2018, TransAlta maintains investment grade ratings from three credit rating agencies. TransAlta is focused on strengthening its financial position and maintaining investment grade credit ratings with these major rating agencies.

Counterparties enter into certain commodity agreements, such as electricity and natural gas purchase and sale contracts, for the purposes of asset-backed sales and proprietary trading. The terms and conditions of these agreements may contain credit-contingent features (such as downgrades in creditworthiness), which if triggered may result in the Corporation having to post collateral to its counterparties.

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; maintaining investment grade credit ratings; 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:

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Accounts payable and accrued liabilities	497	—	—	—	—	—	497
Long-term debt(1)	130	486	91	947	141	1,439	3,234
Commodity risk management assets	58	89	137	125	113	157	679
Other risk management (assets) liabilities	(3)	(3)	(3)	7	—	—	(2)
Finance lease obligations	18	16	9	5	5	10	63
Interest on long-term debt and finance lease obligations(2)	161	152	129	123	84	694	1,343
Dividends payable	58	—	—	—	—	—	58
Total	**919**	**740**	**363**	**1,207**	**343**	**2,300**	**5,872**

(1) Excludes impact of hedge accounting.
(2) 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					
	2019	**2020**	**2021**	**2022**	**2023**	**2024 and thereafter**
Cash flow hedges						
Commodity Derivative Instruments						
Electricity						
Notional amount (thousands MWh)	3,950	3,465	3,424	3,329	3,329	5,966
Average Price ($ per MWh)	66.86	70.75	74.16	76.81	78.74	81.59

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, 2018	Notional amount	Carrying amount	Line item in the statement of financial position	Change in fair value used for measuring ineffectiveness
Commodity price risk				
Cash flow hedges				
Physical power sales	23 MMWh	687	Risk management assets	**60**
Foreign currency risk				
Net investment hedges				
Foreign-denominated debt	USD400	CAD546	Credit facilities, long-term debt and finance lease obligations	**41**

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

As at Dec. 31, 2018	Change in fair value used for measuring ineffectiveness	Cash flow hedge reserve
Commodity price risk		
Cash flow hedges		
Power forecast sales - Centralia	**60**	**508**

	Change in fair value used for measuring ineffectiveness	Foreign currency translation reserve
Net investment hedges		
Net investment in foreign subsidiaries	**41**	**84**

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

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

		Year ended Dec. 31, 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	**—**
		Fuel and purchased power	**—**	Fuel and purchased power	**—**
Foreign exchange forwards on commodity contracts	**—**	Revenue	**—**	Revenue	**—**
Foreign exchange forwards on project hedges	**—**	Property, plant and equipment	**—**	Foreign exchange (gain) loss	**—**
Foreign exchange forwards on US debt	**—**	Foreign exchange (gain) loss	**3**	Foreign exchange (gain) loss	**—**
Cross-currency swaps	**—**	Foreign exchange (gain) loss	**—**	Foreign exchange (gain) loss	**—**
Forward starting interest rate swaps	**—**	Interest expense	**7**	Interest expense	**—**
OCI impact	**(9)**	**OCI impact**	**(57)**	**Net earnings impact**	**—**

Over the next 12 months, the Corporation estimates that approximately $68 million of after-tax gains will be reclassified from AOCI to net earnings. These estimates assume constant natural gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified may vary based on changes in these factors.

		Year ended Dec. 31, 2017 (as reported under IAS 39)			
		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	163	Revenue	(172)	Revenue	—
		Fuel and purchased power	—	Fuel and purchased power	—
Foreign exchange forwards on commodity contracts	—	Revenue	—	Revenue	—
Foreign exchange forwards on project hedges	(1)	Property, plant and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	—	Foreign exchange (gain) loss	3	Foreign exchange (gain) loss	—
Cross-currency swaps	(26)	Foreign exchange (gain) loss	24	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	7	Interest expense	—
OCI impact	136	OCI impact	(138)	Net earnings impact	—

During December 2016, the Corporation entered into a new contract with the Ontario IESO relating to the Mississauga cogeneration facility that principally terminates the generation effective Jan. 1, 2017. Accordingly, in 2017 the Corporation reclassified unrealized pre-tax cash flow commodity hedge losses of $31 million and $15 million of unrealized pre-tax cash flow foreign exchange hedge gains from AOCI to net earnings due to hedge de-designations for accounting purposes. The cash flow hedges were in respect of future gas purchases expected to occur between 2017 and 2018. See Note 9(C) for further details.

Year ended Dec. 31, 2016 (as reported under IAS 39)

		Effective portion		Ineffective portion	
Derivatives in cash flow hedging relationships	Pre-tax gain (loss) recognized in OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss reclassified from OCI	Location of (gain) loss reclassified from OCI	Pre-tax (gain) loss recognized in earnings
Commodity contracts	304	Revenue	(169)	Revenue	—
		Fuel and purchased power	44	Fuel and purchased power	31
Foreign exchange forwards on commodity contracts	(5)	Revenue	(16)	Revenue	(15)
Foreign exchange forwards on project hedges	(1)	Property, plant, and equipment	—	Foreign exchange (gain) loss	—
Foreign exchange forwards on US debt	(2)	Foreign exchange (gain) loss	53	Foreign exchange (gain) loss	—
Cross-currency swaps	(25)	Foreign exchange (gain) loss	(23)	Foreign exchange (gain) loss	—
Forward starting interest rate swaps	—	Interest expense	6	Interest expense	—
OCI impact	271	OCI impact	(105)	Net earnings impact	16

II. Effect of Non-Hedges

For the year ended Dec. 31, 2018, the Corporation recognized a net unrealized loss of $29 million (2017 - gain of $45 million, 2016 - loss of $63 million) related to commodity derivatives.

For the year ended Dec. 31, 2018, a gain of $3 million (2017 - gain of $28 million, 2016 - gain of $9 million) related to foreign exchange and other derivatives was recognized, which is comprised of net unrealized gains of $4 million (2017 - losses of $2 million, 2016 - gains of $4 million) and net realized losses of $1 million (2017 - gains of $30 million, 2016 - gains of $5 million).

F. Collateral

I. Financial Assets Provided as Collateral

At Dec. 31, 2018, the Corporation provided $105 million (2017 - $67 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, 2018, the Corporation held $17 million (2017 - $21 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. If a material adverse event resulted in the Corporation's senior unsecured debt falling below investment grade, the counterparties to such derivative instruments could request ongoing full collateralization.

As at Dec. 31, 2018, the Corporation had posted collateral of $120 million (Dec. 31, 2017 - $131 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 $120 million (Dec. 31, 2017 - $96 million) of collateral to its counterparties.

16. Inventory

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

The components of inventory are as follows:

As at Dec. 31	**2018**	2017
Parts and materials	**113**	118
Coal	**108**	58
Deferred stripping costs	**7**	11
Natural gas	**4**	9
Purchased emission credits	**10**	23
Total	**242**	219

The change in inventory is as follows:

Balance, Dec. 31, 2016	213
Net addition	11
Change in foreign exchange rates	(5)
Balance, Dec. 31, 2017	219
Net addition	**20**
Change in foreign exchange rates	**3**
Balance, Dec. 31, 2018	**242**

No inventory is pledged as security for liabilities.

17. Property, Plant and Equipment

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

	Land	Coal generation	Gas generation	Renewable generation	Mining property and equipment	Assets under construction	Capital spares and other[1]	Total
Cost								
As at Dec. 31, 2016	95	5,876	1,525	3,212	1,265	407	393	12,773
Additions	—	—	—	—	—	334	4	338
Additions - finance lease	—	—	—	—	14	—	—	14
Disposals	—	—	(16)	(1)	(1)	—	(1)	(19)
Impairment charge - Sundance Unit 1 (Note 4)	—	(20)	—	—	—	—	—	(20)
Revisions and additions to decommissioning and restoration costs	—	82	12	15	42	—	—	151
Retirement of assets	—	(84)	(3)	(4)	(22)	—	(6)	(119)
Change in foreign exchange rates	(1)	(87)	3	(23)	(7)	(2)	(2)	(119)
Transfers[(2)(3)]	1	121	461	29	24	(644)	(18)	(26)
As at Dec. 31, 2017	95	5,888	1,982	3,228	1,315	95	370	12,973
Additions[(4)]	**—**	**—**	**—**	**1**	**—**	**275**	**8**	**284**
Additions - finance lease	**—**	**—**	**—**	**—**	**10**	**—**	**—**	**10**
Disposals	**(3)**	**—**	**—**	**—**	**(1)**	**—**	**(3)**	**(7)**
Impairment charges (Note 7)	**—**	**(38)**	**—**	**(11)**	**—**	**—**	**—**	**(49)**
Revisions and additions to decommissioning and restoration costs	**—**	**(12)**	**(1)**	**(3)**	**(16)**	**—**	**—**	**(32)**
Retirement of assets	**—**	**(47)**	**(17)**	**(6)**	**(16)**	**—**	**(4)**	**(90)**
Change in foreign exchange rates	**2**	**105**	**(13)**	**26**	**7**	**4**	**—**	**131**
Transfers	**—**	**41**	**13**	**51**	**39**	**(174)**	**12**	**(18)**
As at Dec. 31, 2018	**94**	**5,937**	**1,964**	**3,286**	**1,338**	**200**	**383**	**13,202**
Accumulated depreciation								
As at Dec. 31, 2016	—	3,212	1,027	922	659	—	129	5,949
Depreciation	—	351	67	123	76	—	18	635
Retirement of assets	—	(62)	(2)	(3)	(18)	—	(5)	(90)
Disposals	—	—	(11)	(1)	—	—	—	(12)
Change in foreign exchange rates	—	(67)	(1)	(4)	(4)	—	—	(76)
Transfers[(2)]	—	(3)	(8)	—	—	—	—	(11)
As at Dec. 31, 2017	—	3,431	1,072	1,037	713	—	142	6,395
Depreciation	**—**	**306**	**79**	**123**	**125**	**—**	**16**	**649**
Retirement of assets	**—**	**(56)**	**(13)**	**(2)**	**(12)**	**—**	**—**	**(83)**
Disposals	**—**	**—**	**—**	**—**	**(1)**	**—**	**(4)**	**(5)**
Change in foreign exchange rates	**—**	**84**	**(3)**	**6**	**5**	**—**	**—**	**92**
Transfers	**—**	**—**	**(7)**	**(3)**	**—**	**—**	**—**	**(10)**
As at Dec. 31, 2018	**—**	**3,765**	**1,128**	**1,161**	**830**	**—**	**154**	**7,038**
Carrying amount								
As at Dec. 31, 2016	95	2,664	498	2,290	606	407	264	6,824
As at Dec. 31, 2017	95	2,457	910	2,191	602	95	228	6,578
As at Dec. 31, 2018	**94**	**2,172**	**836**	**2,125**	**508**	**200**	**229**	**6,164**

(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) In 2017, net transfers of $14 million relate to the transfer of gas equipment to finance lease receivables.
(3) During the second quarter of 2017, the Corporation reclassified approximately $13 million of capital spares and other assets to inventory.
(4) Includes $7 million related to the acquisition of Big Level.

The Corporation capitalized $2 million of interest to PP&E in 2018 (2017 - $9 million) at a weighted average rate of 4.454 per cent (2017 – 5.87 per cent). Finance lease additions in 2018 and 2017 are for mining equipment at the Highvale mine. The carrying amount of total assets under finance leases as at Dec. 31, 2018, was $65 million (2017 - $65 million).

18. 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	2018	2017
Hydro	**259**	259
Wind and Solar	**175**	174
Energy Marketing	**30**	30
Total goodwill	**464**	463

For the purposes of the 2018 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. In 2018, the Corporation relied on the recoverable amounts determined in 2016 for the Hydro and Energy Marketing segments in performing the 2018 annual goodwill impairment review. No impairment of goodwill arose for any segment.

The key assumption impacting the determination of fair value for the Wind and Solar and Hydro segments are electricity production and sales prices. Forecasts of electricity production for each facility are determined taking into consideration contracts for the sale of electricity, historical production, regional supply-demand balances and capital maintenance and expansion plans. Forecasted sales prices for each facility are determined by taking into consideration contract prices for facilities subject to long- or short-term contracts, forward price curves for merchant plants and regional supply-demand balances. Where forward price curves are not available for the duration of the facility’s useful life, prices are determined by extrapolation techniques using historical industry and company-specific data. Electricity prices used in these 2018 models ranged between $6 to $179 per MWh during the forecast period (2017 - $22 to $218 per MWh). Discount rates used for the goodwill impairment calculation in 2018 ranged from 5.3 per cent to 6.2 per cent (2017 – 5.5 per cent to 6.0 per cent). No reasonable possible change in the assumptions would have resulted in an impairment of goodwill.

19. Intangible Assets

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

	Coal rights	Software and other	Power sale contracts	Intangibles under development	Total
Cost					
As at Dec. 31, 2016	178	268	223	24	693
Additions	–	31	–	20	51
Change in foreign exchange rates	–	(3)	–	–	(3)
Transfers	–	18	–	(15)	3
As at Dec. 31, 2017	178	314	223	29	744
Additions[1]	**–**	**–**	**–**	**53**	**53**
Retirements and disposals[2]	**–**	**(2)**	**–**	**–**	**(2)**
Change in foreign exchange rates	**–**	**3**	**–**	**–**	**3**
Transfers	**7**	**24**	**14**	**(36)**	**9**
As at Dec. 31, 2018	**185**	**339**	**237**	**46**	**807**
Accumulated amortization					
As at Dec. 31, 2016	115	163	60	–	338
Amortization	8	24	9	–	41
Change in foreign exchange rates	–	1	–	–	1
Transfers	2	–	(2)	–	–
As at Dec. 31, 2017	125	188	67	–	380
Amortization	**9**	**32**	**9**	**–**	**50**
Retirements and disposals	**–**	**(1)**	**–**	**–**	**(1)**
Change in foreign exchange rates	**–**	**2**	**–**	**–**	**2**
Transfers	**(17)**	**–**	**20**	**–**	**3**
As at Dec. 31, 2018	**117**	**221**	**96**	**–**	**434**
Carrying amount					
As at Dec. 31, 2016	63	105	163	24	355
As at Dec. 31, 2017	53	126	156	29	364
As at Dec. 31, 2018	**68**	**118**	**141**	**46**	**373**

(1) Includes $33 million related to the acquisition of Big Level.
(2) Includes the impairment charge of $1 million relating to Kent Breeze. See Note 7 for further details.

20. Other Assets

The components of other assets are as follows:

As at Dec. 31	2018	2017
South Hedland prepaid transmission access and distribution costs	**72**	75
Deferred licence fees	**11**	13
Project development costs	**47**	53
Deferred service costs	**12**	15
Long-term prepaids and other assets	**53**	44
Loan receivable	**37**	33
Keephills Unit 3 transmission deposit	**2**	4
Total other assets	**234**	237

South Hedland prepaid electricity transmission 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 are primarily comprised of the Corporation's Sundance 7 project in Alberta and project costs for the Pioneer Pipeline project (Note 4(A)). In December 2015, the Corporation repurchased its partner's 50 per cent share in TAMA Power, the jointly controlled entity developing the Sundance 7 project, for consideration of $10 million, payable in four years and an option for its partner to re-enter the development projects of TAMA Power at accumulated cost during this period. Some projects were written off in 2018 as they are no longer proceeding (see Note 7(B)).

Deferred service costs are TransAlta's contracted payments for shared capital projects required at the Genesee Unit 3 and Keephills Unit 3 sites. These costs are amortized over the life of these projects.

Long-term prepaids and other assets include the funded portion of the TransAlta Energy Transition Bill commitments discussed in Note 33.

The loan receivable relates to the advancement by the Corporation's subsidiary, Kent Hills Wind LP, of $37 million (2017 - $38 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. The current portion of nil (2017 - $5 million) is included in accounts receivable and the long-term portion of the $37 million (2017 - $33 million) is included in other assets.

The Keephills Unit 3 transmission deposit is TransAlta's proportionate share of a provincially required deposit. The full amount of the deposit is anticipated to be reimbursed over the next four years to 2021, as long as certain performance criteria are met.

21. Decommissioning and Other Provisions

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

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2016	293	50	343
Liabilities incurred	3	19	22
Liabilities settled	(19)	(31)	(50)
Liabilities disposed(1)	(8)	—	(8)
Accretion	23	—	23
Revisions in estimated cash flows(2)	41	1	42
Revisions in discount rates(2)	110	—	110
Reversals	—	(4)	(4)
Change in foreign exchange rates	(6)	(2)	(8)
Balance, Dec. 31, 2017	437	33	470
Liabilities incurred	**5**	**17**	**22**
Liabilities settled	**(31)**	**(10)**	**(41)**
Accretion	**24**	**—**	**24**
Acquisition of liabilities (Big Level)		**8**	**8**
Revisions in estimated cash flows	**2**	**3**	**5**
Revisions in discount rates	**(37)**	**—**	**(37)**
Reversals	**—**	**(5)**	**(5)**
Change in foreign exchange rates	**7**	**3**	**10**
Balance, Dec. 31, 2018	**407**	**49**	**456**

(1) Relates to the disposition of the Solomon power station and the sale of the Wintering Hills wind facility.
(2) During 2017, mainly as a result of the OCA (see Note 4(O)), the discount rates used for the Canadian coal and mining operations decommissioning provisions were changed to the use of 5 to 15-year rates. The use of lower, shorter-term discount rates increased the corresponding liabilities. On average, these rates decreased by approximately 1.60 to 2.10 per cent. Additionally, the amount and timing of cash outflows for certain Canadian coal plants and mining operations was also revised, resulting in an increase to the corresponding liabilities.

	Decommissioning and restoration	Other	Total
Balance, Dec. 31, 2017	437	33	470
Current portion	40	27	67
Non-current portion	397	6	403
Balance, Dec. 31, 2018	**407**	**49**	**456**
Current portion	**35**	**35**	**70**
Non-current portion	**372**	**14**	**386**

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 billion, which will be incurred between 2019 and 2073. The majority of the costs will be incurred between 2020 and 2050. At Dec. 31, 2018, the Corporation had provided a surety bond in the amount of US$139 million (2017 - US$139 million) in support of future decommissioning obligations at the Centralia coal mine. At Dec. 31, 2018, the Corporation had provided letters of credit in the amount of $122 million (2017 - $120 million) in support of future decommissioning obligations at the Alberta mine. Some of the facilities that are co-located with mining operations do not currently have any decommissioning obligations recorded as the obligations associated with the facilities are indeterminate at this time.

B. Other Provisions

Other provisions include amounts related to a portion of the Corporation's fixed price commitments under several natural gas transportation contracts for firm transportation that is not expected to be used and for vacant leased premises.

Accordingly, the unavoidable costs of meeting these obligations exceed the economic benefits expected to be received. The contracts extend to 2023.

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.

22. Credit Facilities, Long-Term Debt and Finance Lease Obligations

A. Amounts Outstanding

The amounts outstanding are as follows:

As at Dec. 31	**2018**			2017		
	Carrying value	**Face value**	**Interest(1)**	Carrying value	Face value	Interest(1)
Credit facilities(2)	**339**	**339**	**3.8%**	27	27	2.8%
Debentures	**647**	**651**	**5.8%**	1,046	1,051	6.0%
Senior notes(3)	**943**	**955**	**5.4%**	1,499	1,510	6.0%
Non-recourse(4)	**1,236**	**1,250**	**4.4%**	1,022	1,032	4.3%
Other(5)	**39**	**39**	**9.2%**	44	44	9.2%
	3,204	**3,234**		3,638	3,664	
Finance lease obligations	**63**			69		
	3,267			3,707		
Less: current portion of long-term debt	**(130)**			(729)		
Less: current portion of finance lease obligations	**(18)**			(18)		
Total current long-term debt and finance lease obligations	**(148)**			(747)		
Total credit facilities, long-term debt and finance lease obligations	**3,119**			2,960		

(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, 2018 - US$0.7 billion (Dec. 31, 2017 - US$1.2 billion).
(4) Includes US$1 million at Dec. 31, 2018 (Dec. 31, 2017 - US$27 million).
(5) Includes US$21 million at Dec. 31, 2018 (Dec. 31, 2017 - US$24 million) of tax equity financing.

Credit facilities are comprised of the Corporation's $1.25 billion committed syndicated bank credit facility expiring in 2022, TransAlta Renewable's $500 million committed syndicated bank credit facility expiring in 2022 and the Corporation's three bilateral credit facilities totalling $240 million expiring in 2020. The $1.75 billion (Dec. 31, 2017 - $1.5 billion) committed syndicated bank facilities are the primary source for short-term liquidity after the cash flow generated from the Corporation's business. Interest rates on the credit facilities vary depending on the option selected - Canadian prime, bankers' acceptances, US LIBOR, or US base rate - in accordance with a pricing grid that is standard for such facilities.

During 2018, the Corporation's US$200 million committed facility was cancelled and the Corporation's committed syndicated bank credit facility was increased by $250 million.

During 2017:

- TransAlta Renewables entered into a syndicated credit agreement giving it access to a $500 million committed credit facility. The agreement is fully committed for four years. 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. The facility is subject to a number of customary covenants and restrictions in order to maintain access to the funding commitments. In conjunction with the credit agreement, the $350 million credit facility provided by TransAlta was cancelled.

The Corporation has a total of $2.0 billion (Dec. 31, 2017 - $2.0 billion) of committed credit facilities, including TransAlta Renewables' credit facility of $0.5 billion (Dec. 31, 2017 - $0.5 billion). In total, $0.9 billion (Dec. 31, 2017 - $1.4 billion) is not drawn. At Dec. 31, 2018, the $1.1 billion (Dec. 31, 2017 - $627 million) of credit utilized under these facilities was comprised of actual drawings of $339 million (Dec. 31, 2017 - $27 million) and letters of credit of $720 million (Dec. 31, 2017 - $677 million). The Corporation is in compliance with the terms of the credit facilities and all undrawn amounts are fully available. In addition to the $0.9 billion available under the credit facilities, the Corporation also has $89 million of available cash and cash equivalents and $35 million ($27 million principal portion) in cash restricted for repayment of the OCP bonds (see section E below).

Debentures bear interest at fixed rates ranging from 5.0 per cent to 7.3 per cent and have maturity dates ranging from 2020 to 2030.

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

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

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

During 2017, the Corporation's US$400 million 1.90 per cent senior note matured and was paid out using existing liquidity. The repayment was hedged with a currency swap. The maturity value of the bond was $434 million.

A total of US$400 million (2017 - US$480 million) of the senior notes has been designated as a hedge of the Corporation's net investment in US foreign operations.

Non-recourse debt consists of bonds and debentures that have maturity dates ranging from 2023 to 2033 and bear interest at rates ranging from 2.95 per cent to 6.26 per cent.

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

During 2017, TransAlta Renewables closed a $260 million non-recourse bond offering by way of a private placement. At the same time, the Corporation early redeemed the $191 million face value CHD non-recourse debentures on Oct. 12, 2017. The redemption price was $201 million, including an early redemption premium of $6 million, recognized in net interest expense and accrued and unpaid interest of $4 million.

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 financing assumed in the Lakeswind wind acquisition.

TransAlta's debt has terms and conditions, including financial covenants, that are considered normal and customary. As at Dec. 31, 2018, the Corporation was in compliance with all debt covenants.

B. Restrictions on Non-Recourse Debt

The Melancthon Wolfe Wind, Pingston, TAPC Holdings LP, New Richmond, KHWLP and OCP non-recourse bonds with a carrying value of $1,235 million (Dec. 31, 2017 - $1,022 million) are subject to customary financing conditions and covenants that may restrict the Corporation's ability to access funds generated by the facilities' operations. Upon meeting certain distribution tests, typically performed once per quarter, the funds are able to be distributed by the subsidiary entities to their respective parent entity. These conditions include meeting a debt service coverage ratio prior to distribution, which was met by these entities in the fourth quarter. However, funds in these entities that have accumulated since the fourth quarter test will remain there until the next debt service coverage ratio can be calculated in the first quarter of 2019. At Dec. 31, 2018, $33 million (Dec. 31, 2017 -$35 million) of cash was subject to these financial restrictions.

Additionally, certain non-recourse bonds require that certain reserve accounts be established and funded through cash held on deposit and/or by providing letters of credit. The Corporation has elected to use letters of credit as at Dec. 31, 2018.

C. Security

Non-recourse debts of $766 million in total (Dec. 31, 2017 - $848 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 includes certain renewable generation facilities with total carrying amounts of $1,021 million at Dec. 31, 2018 (Dec. 31, 2017 - $1,107 million). At Dec. 31, 2018, a non-recourse bond of approximately $127 million (Dec. 31, 2017 - $174 million) was secured by a first ranking charge over the equity interests of the issuer that issued the non-recourse bond.

The new TransAlta OCP bonds with a carrying value of $342 million 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

	2019	**2020**	**2021**	**2022**	**2023**	**2024 and thereafter**	**Total**
Principal repayments[1]	130	486	91	947	141	1,439	3,234

(1) Excludes impact of derivatives.

E. Restricted Cash

The Corporation has $31 million (Dec. 31, 2017 - $30 million) of restricted cash related to the Kent Hills project 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 Q1 2019.

The Corporation also has $35 million (Dec. 31, 2017 - nil) 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 2019.

F. Finance Lease Obligations

Amounts payable for mining assets and other finance leases are as follows:

As at Dec. 31	**2018**		2017	
	Minimum lease payments	**Present value of minimum lease payments**	Minimum lease payments	Present value of minimum lease payments
Within one year	**21**	**20**	20	20
Second to fifth years inclusive	**39**	**35**	43	38
More than five years	**10**	**8**	15	11
	70	**63**	78	69
Less: interest costs	**7**	**—**	9	—
Total finance lease obligations	**63**	**63**	69	69

Included in the Consolidated Statements of Financial Position as:		
Current portion of finance lease obligations	**18**	18
Long-term portion of finance lease obligations	**45**	51
	63	69

G. 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 uncommitted $100 million demand letter of credit facility. 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, 2018, was $720 million (2017 - $677 million) with no (2017 - nil) amounts exercised by third parties under these arrangements.

23. 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	**2018**	2017
Defined benefit obligation (Note 28)	**227**	235
Long-term incentive accruals (Note 27)	**9**	16
Other	**51**	46
Total[(1)]	**287**	297

(1) 2017 deferred revenues of $62 million have been reclassified on the statement of financial position to contract liabilities as required under IFRS 15. See Note 3(A) and Note 5(B) for further details.

24. 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	**2018**		2017	
	Common shares *(millions)*	**Amount**	Common shares *(millions)*	Amount
Issued and outstanding, beginning of year	**287.9**	**3,094**	287.9	3,095
Purchased and cancelled under the NCIB	**(3.3)**	**(35)**	—	—
	284.6	**3,059**	287.9	3,095
Amounts receivable under Employee Share Purchase Plan	**—**	**—**	—	(1)
Issued and outstanding, end of year	**284.6**	**3,059**	287.9	3,094

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 retained earnings.

The following are the effects of the Corporation's purchase and cancellation of the common shares during the year ended Dec. 31, 2018:

Total shares purchased[(1)]		**3,264,500**
Average purchase price per share	**$**	**7.02**
Total cost		**23**
Weighted average book value of shares cancelled		**35**
Increase to retained earnings		**12**

(1) Includes 204,000 shares that were repurchased but were not cancelled due to timing differences between the transaction date and settlement date.

C. Shareholder Rights Plan

The Corporation initially adopted the Shareholder Rights Plan in 1992, which has been revised since that time to ensure conformity with current practices. 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 22, 2016. The primary objective of the Shareholder Rights Plan is to provide the Board sufficient time to explore and develop alternatives for maximizing shareholder value if a takeover bid is made for the Corporation and to provide every shareholder with an equal opportunity to participate in such a bid. When an acquiring shareholder acquires 20 per cent or more of the Corporation's common shares, other than by way of a "permitted bid" or a "competing permitted bid" (as defined in the Shareholder Rights Plan), where the offer is made to all shareholders by way of a takeover bid circular, 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 acquire an additional $200 worth of common shares for $100.

D. Earnings per Share

Year ended Dec. 31	**2018**	2017	2016
Net earnings (loss) attributable to common shareholders	**(248)**	(190)	117
Basic and diluted weighted average number of common shares outstanding (millions)	**287**	288	288
Net earnings (loss) per share attributable to common shareholders, basic and diluted	**(0.86)**	(0.66)	0.41

E. Dividends

On Oct. 10, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Jan. 1, 2019.

On Dec. 14, 2018, the Corporation declared a quarterly dividend of $0.04 per common share, payable on Apr. 1, 2019.

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

25. Preferred Shares

A. Issued and Outstanding

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

As at Dec. 31	**2018**		2017	
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 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.

II. 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.

III. 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 has 10.2 million Series A Shares and 1.8 million Series B Shares issued and outstanding at Dec. 31, 2018.

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%.

IV. 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, they 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, 2018, are as follows:

Series	Rate during term	Annual dividend rate per share *($)*	Next conversion date	Rate spread over Benchmark *(per cent)*	Convertible to Series
A	Fixed	0.67725	March 31, 2021	2.03	B
B	Floating	0.93575	March 31, 2021	2.03	A
C	Fixed	1.00675	June 30, 2022	3.10	D
D	Floating	—	—	3.10	C
E	Fixed	1.29850	Sept. 30, 2022	3.65	F
F	Floating	—	—	3.65	E
G	Fixed	1.32500	Sept. 30, 2019	3.80	H
H	Floating	—	—	3.80	G

B. Dividends

The following table summarizes the preferred share dividends declared in 2018, 2017 and 2016:

	Total dividends declared ($)		
Series	**2018**	2017	2016
A	**9**	5	10
B	**1**	1	1
C	**14**	9	16
E	**15**	8	14
G	**11**	7	11
Total for the year	**50**	30	52

26. Accumulated Other Comprehensive Income

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

	2018	2017
Currency translation adjustment		
Opening balance, Jan. 1	**(26)**	(1)
Losses on translating net assets of foreign operations, net of reclassifications to net earnings, net of tax(1)	**84**	(89)
Gains on financial instruments designated as hedges of foreign operations, net of reclassifications to net earnings, net of tax(2)	**(41)**	64
Balance, Dec. 31	**17**	(26)
Cash flow hedges		
Opening balance, Jan. 1	**562**	456
Gains on derivatives designated as cash flow hedges, net of reclassifications to net earnings and to non-financial assets, net of tax(3)	**(54)**	106
Balance, Dec. 31	**508**	562
Employee future benefits		
Opening balance, Jan. 1	**(44)**	(38)
Net actuarial gains (losses) on defined benefit plans, net of tax(4)	**15**	(6)
Balance, Dec. 31	**(29)**	(44)
Other		
Opening balance, Jan. 1	**(3)**	(18)
Change in ownership of TransAlta Renewables	**4**	4
Intercompany investments at FVOCI	**(16)**	11
Balance, Dec. 31	**(15)**	(3)
Accumulated other comprehensive income	**481**	489

(1) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 11 million).
(2) Net of income tax of nil for the year ended Dec. 31, 2018 (2017 - 4 million).
(3) Net of income tax of 12 million for the year ended Dec. 31, 2018 (2017 - 108 million).
(4) Net of income tax of 5 million for the year ended Dec. 31, 2018 (2017 - 4 million).

27. 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. 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 expense related to this plan is recognized during the period earned, with the corresponding payable recorded in liabilities. The liability is 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 2018 was $8 million (2017 - $15 million , 2016 - $17 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 nil in 2018 (2017 - $1 million, 2016 - $3 million).

C. Stock Option Plans

The Corporation is authorized to grant options to purchase up to an aggregate of 13 million common shares at prices based on the market price of the shares on the TSX as determined on the grant date. The plan provides for grants of options to all full-time employees, including executives, designated by the Human Resources Committee from time to time.

In February 2018, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.45 that vest after a three-year period and expire seven years after issuance. In March 2017, the Corporation granted executive officers of the Corporation a total of 0.7 million stock options with an exercise price of $7.25 that vest after a three-year period and expire seven years after issuance. In February 2016, the Corporation granted executive officers of the Corporation a total of 1.1 million stock options with an exercise price of $5.93 that vest after a three-year period and expire seven years after issuance. The expense recognized relating to these grants during 2018 was approximately $1 million (2017 - approximately $1 million, 2016 - less than $1 million).

The total options outstanding and exercisable under these stock option plans at Dec. 31, 2018, are outlined below:

	Options outstanding		
Range of exercise prices *($ per share)*	**Number of options** *(millions)*	**Weighted average remaining contractual life** *(years)*	**Weighted average exercise price** *($ per share)*
5.00 - 8.00	2.3	5	6.71
22.00 - 30.00[1]	0.5	1.1	23.69
5.00 - 30.00	**2.8**	**4.3**	**9.66**

(1) Options currently exercisable.

D. Employee Share Purchase Plan

Under the terms of the employee share purchase plan, the Corporation extended interest-free loans (up to 30 per cent of an employee's base salary) to employees below executive level and allowed for payroll deductions over a three-year period to repay the loan. Executives were not eligible for this program in accordance with the Sarbanes-Oxley legislation. An agent purchased these common shares on the open market on behalf of employees at prices based on the market price of the shares as determined on the date of purchase. Employee sales of these shares were handled in the same manner. At Dec. 31, 2018, amounts receivable from employees under the plan was nil (2017 - less than $1 million).

On Jan. 14, 2016, the Corporation suspended its employee share purchase plan.

28. 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, 2018. The latest actuarial valuation for accounting purposes of the Highvale and Canadian pension plans was at Dec. 31, 2016. The measurement date used for all plans to determine the fair value of plan assets and the present value of the defined benefit obligation was Dec. 31, 2018.

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 2018 for the amount of $80 million to secure the obligations under the supplemental plan.

The Corporation provides other health and dental benefits to the age of 65 for both disabled members and retired members through its other post-employment benefits plans. The latest actuarial valuations for accounting purposes of the Canadian and US plans were as at Dec. 31, 2016, and Jan. 1, 2018, respectively. The measurement date used to determine the present value obligation for both plans was Dec. 31, 2018.

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

Year ended Dec. 31, 2017	Registered	Supplemental	Other	Total
Current service cost	7	2	1	10
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	20	3	1	24
Interest on plan assets	(15)	—	—	(15)
Defined benefit expense	14	5	2	21
Defined contribution expense	11	—	—	11
Net expense	25	5	2	32

Year ended Dec. 31, 2016	Registered	Supplemental	Other	Total
Current service cost	7	2	2	11
Administration expenses	2	—	—	2
Interest cost on defined benefit obligation	21	3	1	25
Interest on plan assets	(16)	—	—	(16)
Defined benefit expense	14	5	3	22
Defined contribution expense	15	—	—	15
Net expense	29	5	3	37

C. Status of Plans

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

As at Dec. 31, 2018	**Registered**	**Supplemental**	**Other**	**Total**
Fair value of plan assets	**368**	**13**	**—**	**381**
Present value of defined benefit obligation	**(514)**	**(80)**	**(25)**	**(619)**
Funded status - plan deficit	**(146)**	**(67)**	**(25)**	**(238)**
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	**(5)**	**(5)**	**(1)**	**(11)**
Other long-term liabilities	**(141)**	**(62)**	**(24)**	**(227)**
Total amount recognized	**(146)**	**(67)**	**(25)**	**(238)**

As at Dec. 31, 2017	Registered	Supplemental	Other	Total
Fair value of plan assets	416	12	—	428
Present value of defined benefit obligation	(561)	(87)	(27)	(675)
Funded status - plan deficit	(145)	(75)	(27)	(247)
Amount recognized in the consolidated financial statements:				
Accrued current liabilities	(4)	(6)	(2)	(12)
Other long-term liabilities	(141)	(69)	(25)	(235)
Total amount recognized	(145)	(75)	(27)	(247)

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, 2016	423	10	—	433
Interest on plan assets	15	—	—	15
Net return on plan assets	26	—	—	26
Contributions	6	6	—	12
Benefits paid	(51)	(4)	—	(55)
Administration expenses	(2)	—	—	(2)
Effect of translation on US plans	(1)	—	—	(1)
As at Dec. 31, 2017	416	12	—	428
Interest on plan assets	**13**	**—**	**—**	**13**
Net return on plan assets	**(25)**	**—**	**—**	**(25)**
Contributions	**5**	**6**	**1**	**12**
Benefits paid	**(42)**	**(5)**	**(1)**	**(48)**
Administration expenses	**(1)**	**—**	**—**	**(1)**
Effect of translation on US plans	**2**	**—**	**—**	**2**
As at Dec. 31, 2018	**368**	**13**	**—**	**381**

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

Year ended Dec. 31, 2018	**Level I**	**Level II**	**Level III**	**Total**
Equity securities				
Canadian	**—**	**65**	**—**	**65**
US	**—**	**26**	**—**	**26**
International	**—**	**101**	**—**	**101**
Private	**—**	**—**	**1**	**1**
Bonds				
AAA	**—**	**48**	**—**	**48**
AA	**—**	**64**	**—**	**64**
A	**—**	**39**	**—**	**39**
BBB	**1**	**21**	**—**	**22**
Below BBB	**—**	**3**	**—**	**3**
Money market and cash and cash equivalents	**(2)**	**14**	**—**	**12**
Total	**(1)**	**381**	**1**	**381**

Year ended Dec. 31, 2017	Level I	Level II	Level III	Total
Equity securities				
Canadian	—	76	—	76
US	—	31	—	31
International	—	118	—	118
Private	—	—	1	1
Bonds				
AAA	—	43	—	43
AA	—	71	—	71
A	—	44	—	44
BBB	1	25	—	26
Below BBB	—	5	—	5
Money market and cash and cash equivalents	(1)	14	—	13
Total	—	427	1	428

Plan assets do not include any common shares of the Corporation at Dec. 31, 2018, and Dec. 31, 2017. The Corporation charged the registered plan $0.1 million for administrative services provided for the year ended Dec. 31, 2018 (2017 - $0.1 million).

E. Defined Benefit Obligation

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

	Registered	Supplemental	Other	Total
Present value of defined benefit obligation as at Dec. 31, 2016	554	82	27	663
Current service cost	7	2	1	10
Interest cost	20	3	1	24
Benefits paid	(51)	(4)	—	(55)
Actuarial gain arising from demographic assumptions	4	1	—	5
Actuarial loss arising from financial assumptions	26	3	—	29
Actuarial gain (loss) arising from experience adjustments	3	—	(1)	2
Effect of translation on US plans	(2)	—	(1)	(3)
Present value of defined benefit obligation as at Dec. 31, 2017	**561**	**87**	**27**	**675**
Current service cost	**9**	**2**	**1**	**12**
Interest cost	**18**	**3**	**1**	**22**
Benefits paid	**(42)**	**(5)**	**(1)**	**(48)**
Actuarial (gain) loss arising from financial assumptions	**(35)**	**(7)**	**(2)**	**(44)**
Actuarial (gain) loss arising from experience adjustments	**—**	**—**	**(1)**	**(1)**
Effect of translation on US plans	**3**	**—**	**—**	**3**
Present value of defined benefit obligation as at Dec. 31, 2018	**514**	**80**	**25**	**619**

The weighted average duration of the defined benefit plan obligation as at Dec. 31, 2018 is 14 years.

F. Contributions

The expected employer contributions for 2019 for the defined benefit pension and other post-employment benefit plans are as follows:

	Registered	Supplemental	Other	Total
Expected employer contributions	**5**	**4**	**2**	**11**

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, 2018			As at Dec. 31, 2017		
(per cent)	**Registered**	**Supplemental**	**Other**	Registered	Supplemental	Other
Accrued benefit obligation						
Discount rate	**3.9**	**3.8**	**3.9**	3.3	3.3	3.4
Rate of compensation increase	**2.5**	**3.0**	**—**	2.9	3.0	—
Assumed health care cost trend rate						
Health care cost escalation(1)(3)	**—**	**—**	**7.1**	—	—	7.8
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Benefit cost for the year						
Discount rate	**3.3**	**3.3**	**3.4**	3.7	3.6	3.7
Rate of compensation increase	**2.6**	**3.0**	**—**	2.6	3.0	—
Assumed health care cost trend rate						
Health care cost escalation(2)(4)	**—**	**—**	**7.6**	—	—	7.9
Dental care cost escalation	**—**	**—**	**4.0**	—	—	4.0
Provincial health care premium escalation	**—**	**—**	**—**	—	—	—

(1) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2029 and remaining at that level thereafter for the US and decreasing gradually by 0.3% per year to 4.5% in 2027 for Canada.
(2) 2018 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(3) 2017 Post- and pre-65 rates: decreasing gradually to 4.5% by 2027 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 4.5% in 2027 for Canada.
(4) 2017 Post- and pre-65 rates: decreasing gradually to 4.5% by 2026 and remaining at that level thereafter for the US and decreasing gradually by 0.30% per year to 5% in 2024 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, 2018	**Registered**	**Supplemental**	**Other**	**Pension**	**Other**
1% decrease in the discount rate	**70**	**11**	**3**	**2**	**1**
1% increase in the salary scale	**10**	**1**	**—**	**—**	**—**
1% increase in the health care cost trend rate	**—**	**—**	**2**	**—**	**—**
10% improvement in mortality rates	**18**	**3**	**—**	**1**	**—**

29. Joint Arrangements

Joint arrangements at Dec. 31, 2018, included the following:

Joint operations	Segment	Ownership *(per cent)*	Description
Sheerness	Coal	50	Coal-fired plant in Alberta, of which TA Cogen has a 50 per cent interest, operated by ATCO Power
Genesee Unit 3	Coal	50	Coal-fired plant in Alberta operated by Capital Power Corporation
Keephills Unit 3	Coal	50	Coal-fired plant in Alberta operated by TransAlta
Goldfields Power	Gas	50	Gas-fired plant in Australia operated by TransAlta
Fort Saskatchewan	Gas	60	Cogeneration plant in Alberta, of which TA Cogen has a 60 per cent interest, operated by TransAlta
Fortescue River Gas Pipeline	Gas	43	Natural gas pipeline in Western Australia, operated by DBP Development Group
McBride Lake	Wind	50	Wind generation facility in Alberta operated by TransAlta
Soderglen	Wind	50	Wind generation facility in Alberta operated by TransAlta
Pingston	Hydro	50	Hydro facility in British Columbia operated by TransAlta

30. Cash Flow Information

A. Change in Non-Cash Operating Working Capital

Year ended Dec. 31	2018	2017	2016
(Use) source:			
Accounts receivable	**58**	(228)	(23)
Prepaid expenses	**19**	(75)	5
Income taxes receivable	**—**	8	(4)
Inventory	**(21)**	(7)	11
Accounts payable, accrued liabilities, and provisions	**(97)**	186	81
Income taxes payable	**(3)**	2	3
Change in non-cash operating working capital	**(44)**	(114)	73

B. Changes in Liabilities from Financing Activities

	Balance Dec. 31, 2017	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2018
Long-term debt and finance lease obligations	3,707	(540)	10	—	95	(5)	3,267
Dividends payable (common and preferred)	34	(86)	—	107	—	3	58
Total liabilities from financing activities	**3,741**	**(626)**	**10**	**107**	**95**	**(2)**	**3,325**

	Balance Dec. 31, 2016	Net cash flows	New leases	Dividends declared	Foreign exchange impact	Other	Balance Dec. 31, 2017
Long-term debt and finance lease obligations	4,361	(545)	14	—	(115)	(8)	3,707
Dividends payable (common and preferred)	54	(86)	—	64	—	2	34
Total liabilities from financing activities	4,415	(631)	14	64	(115)	(6)	3,741

31. Capital

TransAlta's capital is comprised of the following:

As at Dec. 31	2018	2017	Increase/ (decrease)
Long-term debt[1]	**3,267**	3,707	**(440)**
Equity			
Common shares	**3,059**	3,094	**(35)**
Preferred shares	**942**	942	**—**
Contributed surplus	**11**	10	**1**
Deficit	**(1,496)**	(1,209)	**(287)**
Accumulated other comprehensive income	**481**	489	**(8)**
Non-controlling interests	**1,137**	1,059	**78**
Less: available cash and cash equivalents[2]	**(89)**	(314)	**225**
Less: principal portion of restricted cash on OCP Bonds[3]	**(27)**	—	**(27)**
Less: fair value asset of hedging instruments on long-term debt[4]	**(10)**	(30)	**20**
Total capital	**7,275**	7,748	**(473)**

(1) Includes finance lease obligations, amounts outstanding under credit facilities, tax equity liability 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 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.

In 2018, the Corporation continued to focus on reducing overall debt. The Corporation's overall capital management strategy and its objectives in managing capital have remained unchanged from Dec. 31, 2017, and are as follows:

A. Maintain an Investment Grade Credit Rating

The Corporation operates in a long-cycle and capital-intensive commodity business, and it is therefore a priority to maintain an investment grade credit rating as it allows the Corporation to access capital markets at reasonable interest rates. Key rating agencies assess TransAlta's credit rating using a variety of methodologies, including financial ratios. These methodologies and ratios are not publicly disclosed. TransAlta's management has developed its own definitions of metrics, ratios and targets to manage the Corporation's capital. These metrics and ratios are not defined under IFRS, and may not be comparable to those used by other entities or by rating agencies.

The Corporation has an investment grade credit rating from Standard & Poor's (negative outlook), DBRS (stable outlook) and Fitch Ratings (stable outlook). In December 2015, Moody's downgraded the Corporation below investment grade to Ba1 with a stable outlook and in June 2018 Moody's revised their rating outlook to positive from stable. During 2018, Fitch Ratings reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with a stable outlook; DBRS Limited reaffirmed the Corporation's Unsecured Debt rating and Medium-Term Notes rating of BBB (low), the Preferred Shares rating of Pfd-3 (low), and Issuer Rating of BBB (low) with a stable outlook; and Standard and Poor's reaffirmed the Corporation's Unsecured Debt rating and Issuer Rating of BBB- with negative outlook. The Corporation is focused on strengthening its financial position and cash flow coverage ratios to achieve stable investment grade credit ratings. 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. Strengthening the Corporation's financial position 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 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	2018	2017	Target
Funds from operations before interest to adjusted interest coverage (times)	**4.8**	4.3	4 to 5
Adjusted funds from operations to adjusted net debt (%)	**20.8**	20.4	20 to 25
Adjusted net debt to comparable earnings before interest, taxes, depreciation and amortization (times)	**3.7**	3.6	3.0 to 3.5

Funds from Operations ("FFO") before Interest to Adjusted Interest Coverage is calculated as FFO plus interest on debt (net of capitalized interest) divided by interest on debt plus 50 per cent of dividends paid on preferred shares. FFO is calculated as cash flow from operating activities before changes in working capital and is adjusted for transactions and amounts that the Corporation believes are not representative of ongoing cash flows from operations. The Corporation's goal is to maintain this ratio in a range of four to five times.

Adjusted FFO to Adjusted Net Debt is calculated as FFO less 50 per cent of dividends paid on preferred shares divided by net debt (current and long-term debt plus 50 per cent of outstanding preferred shares less available cash and cash equivalents and including fair value assets of hedging instruments on debt). The Corporation's goal is to maintain this ratio in a range of 20 to 25 per cent.

Adjusted Net Debt to Comparable Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") is calculated as net debt divided by comparable EBITDA. 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. The Corporation's goal is to maintain this ratio in a range of 3.0 to 3.5 times.

At times, the credit ratios may be outside of the specified target ranges while the Corporation realigns its capital structure. During 2018, the Corporation continued to strengthen its financial position and reduce debt.

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, 2018 and 2017, cash inflows and outflows are summarized below. The Corporation manages variations in working capital using existing liquidity under credit facilities.

Year ended Dec. 31	2018	2017	Increase (decrease)
Cash flow from operating activities	**820**	626	194
Change in non-cash working capital	**44**	114	(70)
Cash flow from operations before changes in working capital	**864**	740	124
Dividends paid on common shares	**(46)**	(46)	—
Dividends paid on preferred shares	**(40)**	(40)	—
Distributions paid to subsidiaries' non-controlling interests	**(165)**	(172)	7
Property, plant and equipment expenditures(1)	**(277)**	(338)	61
Inflow	**336**	144	192

(1) Includes growth capital associated with the South Hedland Power Station.

TransAlta maintains sufficient cash balances and committed credit facilities to fund periodic net cash outflows related to its business. At Dec. 31, 2018, $0.9 billion (2017 - $1.4 billion) of the Corporation's available credit facilities were not drawn.

Periodically, 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.

32. Related-Party Transactions

Details of the Corporation's principal operating subsidiaries at Dec. 31, 2018, 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	60.9	Generation and sale of electricity

Transactions between the Corporation and its subsidiaries have been eliminated on consolidation and are not disclosed.

Transactions with Key Management Personnel
TransAlta's key management personnel include the President and CEO and members of the senior management team that report directly to the President and CEO, and the members of the Board.

Key management personnel compensation is as follows:

Year ended Dec. 31	2018	2017	2016
Total compensation	**17**	24	20
Comprised of:			
Short-term employee benefits	**11**	14	8
Post-employment benefits	**2**	2	2
Share-based payments	**4**	8	10

33. Commitments and Contingencies

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

	2019	2020	2021	2022	2023	2024 and thereafter	Total
Natural gas, transportation and other purchase contracts	28	15	13	11	12	157	**236**
Transmission	9	10	6	4	3	—	**32**
Coal supply and mining agreements	158	160	27	24	24	95	**488**
Long-term service agreements	64	86	32	17	8	34	**241**
Non-cancellable operating leases	8	8	8	7	4	45	**80**
Growth	324	79	144	—	—	—	**547**
TransAlta Energy Transition Bill	6	7	6	6	6	—	**31**
Total	**597**	**365**	**236**	**69**	**57**	**331**	**1,655**

A. Natural Gas, Transportation and Other Purchase Contracts

Several of the Corporation's plants have fixed price natural gas purchase and related transportation contracts in place. Other purchase contracts relate to commitments for goods and services.

B. Transmission

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

C. Coal Supply and Mining Agreements

Various coal supply and associated rail transport contracts are in place to provide coal for use in production at the Centralia coal plant. The coal supply agreements allow TransAlta to take delivery of coal at fixed volumes with dates extending to 2020.

Commitments related to mining agreements include the Corporation's share of commitments for mining agreements related to its Sheerness and Genesee Unit 3 joint operations, and certain other mining royalty agreements. Some of these commitments have been reduced due to the cessation of coal-fired emissions from the Genesee 3 and Sheerness coal-fired plants on or before Dec. 31, 2030.

D. Long-Term Service Agreements

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

E. Non-Cancellable Operating Leases

TransAlta has operating leases in place for buildings, vehicles and various types of equipment.

During the year ended Dec. 31, 2018, $8 million (2017 - $7 million, 2016 - $9 million) was recognized as an expense in respect of these operating leases. Sublease payments received during 2018, 2017 and 2016 were less than $1 million. No contingent rental payments were made in respect of these operating leases.

F. Growth

Commitments for growth relate to the Big Level, Antrim and Windrise wind development projects, the coal-to-gas conversions, and to the Corporation's 50% share of the Pioneer Pipeline project.

G. TransAlta Energy Transition Bill Commitments

On July 30, 2015, the Corporation announced that it would formalize its commitment to invest US$55 million over the remaining nine-year life of the Centralia coal plant to support energy efficiency, economic and community development, and education and retraining initiatives in Washington State by waiving its right to terminate the commitment on the basis of the level of contract sales of the Centralia plant. As of Dec. 31, 2018, the Corporation has funded approximately US$33 million of the commitment, which is recognized in other assets in the Consolidated Statements of Financial Position.

H. Other

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

I. Contingencies

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

I. Line Loss Rule Proceeding

The Corporation has been participating in a line loss rule proceeding before the Alberta Utilities Commission ("AUC"). The AUC determined that it has the ability to retroactively adjust line loss charges going back to 2006 and directed the AESO to, among other things, perform such retroactive calculations. The various decisions by the AUC are, however, subject to appeal and challenge. A recent decision by the AUC determined the methodology to be used retroactively and it is now possible to estimate the total retroactive potential exposure faced by the Corporation for its non-PPA MWs. The current estimate of exposure based on known data is $15 million and therefore the Corporation increased the provision from $7.5 million to $15 million in 2018.

II. FMG Disputes
The Corporation is currently engaged in two disputes with Fortescue Metals Group Ltd. ("FMG"). The first arose as a result of FMG's purported termination of the South Hedland PPA. TransAlta has sued FMG, seeking payment of amounts invoiced and not paid under the South Hedland PPA, as well as a declaration that the PPA is valid and in force. FMG, on the other hand, seeks a declaration that the PPA was lawfully terminated.

The second matter involves FMG's claims against TransAlta related to the transfer of the Solomon Power Station to FMG. FMG claims certain amounts related to the condition of the facility while TransAlta claims certain outstanding costs that should be reimbursed.

III. Balancing Pool Dispute
Pursuant to a written agreement, the Balancing Pool paid the Corporation approximately $157 million on March 29, 2018, as part of the net book value payment required on termination of the Sundance B and C PPAs. The Balancing Pool, however, excluded certain mining and corporate assets that the Corporation believes should be included in the net book value calculation, which amounts to an additional $56 million. The dispute is currently proceeding through arbitration.

34. Segment Disclosures

A. Description of Reportable Segments
The Corporation has eight reportable segments as described in Note 1.

B. Reported Segment Earnings (Loss) and Segment Assets
I. Earnings Information

Year ended Dec. 31, 2018	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	912	442	232	165	282	156	67	(7)	2,249
Fuel and purchased power	666	314	96	8	17	6	—	(7)	1,100
Gross margin	246	128	136	157	265	150	67	—	1,149
Operations, maintenance and administration	171	61	48	37	50	38	24	86	515
Depreciation and amortization	241	74	43	49	110	30	2	25	574
Asset impairment charge	38	—	—	—	12	—	—	23	73
Taxes, other than income taxes	13	5	1	—	8	3	—	1	31
Net other operating expense (income)	(198)	—	—	—	(6)	—	—	—	(204)
Operating income (loss)	(19)	(12)	44	71	91	79	41	(135)	160
Finance lease income	—	—	8	—	—	—	—	—	8
Net interest expense									(250)
Foreign exchange loss									(15)
Gain on sale of assets and other									1
Losses before income taxes									(96)

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Revenues	999	435	261	135	287	121	69	—	2,307
Fuel and purchased power	585	293	101	14	17	6	—	—	1,016
Gross margin	414	142	160	121	270	115	69	—	1,291
Operations, maintenance and administration	192	51	50	31	48	37	24	84	517
Depreciation and amortization	317	73	38	37	111	31	2	26	635
Asset impairment charge	20	—	—	—	—	—	—	—	20
Taxes, other than income taxes	13	4	1	—	8	3	—	1	30
Net other operating expense (income)	(40)	—	(9)	—	—	—	—	—	(49)
Operating income (loss)	(88)	14	80	53	103	44	43	(111)	138
Finance lease income	—	—	11	43	—	—	—	—	54
Net interest expense									(247)
Foreign exchange loss									(1)
Gain on sale of assets									2
Earnings before income taxes									(54)

Year ended Dec. 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind	Hydro	Energy Marketing	Corporate	Total
Revenues	1,048	354	402	119	272	126	76	—	2,397
Fuel and purchased power	451	281	185	20	18	8	—	—	963
Gross margin	597	73	217	99	254	118	76	—	1,434
Operations, maintenance and administration	178	54	54	25	52	33	24	69	489
Depreciation and amortization	242	61	100	17	119	33	3	26	601
Asset impairment reversals	—	—	—	—	28	—	—	—	28
Taxes, other than income taxes	13	4	1	1	8	3	—	1	31
Net other operating expense (income)	(2)	—	(191)	—	(1)	—	—	1	(193)
Operating income (loss)	166	(46)	253	56	48	49	49	(97)	478
Finance lease income	—	—	14	52	—	—	—	—	66
Net interest expense									(229)
Foreign exchange loss									(5)
Gain on sale of assets									4
Earnings before income taxes									314

Included in revenues of the Wind and Solar Segment for the year ended Dec. 31, 2018 is $16 million (2017 -$18 million, 2016 - $19 million) of incentives received under a Government of Canada program in respect of power generation from qualifying wind projects.

II. Selected Consolidated Statements of Financial Position Information

As at Dec. 31, 2018	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Goodwill	—	—	—	—	**175**	**259**	**30**	—	**464**
PP&E	**2,587**	**332**	**391**	**554**	**1,799**	**481**	**1**	**19**	**6,164**
Intangible assets	**81**	**7**	**4**	**41**	**173**	**4**	**11**	**52**	**373**

As at Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Goodwill	—	—	—	—	174	259	30	—	463
PP&E	2,902	370	416	606	1,764	497	1	22	6,578
Intangibles	91	7	3	42	149	3	13	56	364

III. Selected Consolidated Statements of Cash Flows Information

Additions to non-current assets are as follows:

Year ended Dec. 31, 2018	**Canadian Coal**	**US Coal**	**Canadian Gas**	**Australian Gas**	**Wind and Solar**	**Hydro**	**Energy Marketing**	**Corporate**	**Total**
Additions to non-current assets:									
PP&E	**101**	**14**	**21**	**6**	**117**	**16**	—	**2**	**277**
Intangible assets	**3**	—	—	—	—	—	—	**17**	**20**

Year ended Dec. 31, 2017	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	116	35	31	114	20	16	—	6	338
Intangibles	5	1	—	29	—	—	—	16	51

Year ended Dec. 31, 2016	Canadian Coal	US Coal	Canadian Gas	Australian Gas	Wind and Solar	Hydro	Energy Marketing	Corporate	Total
Additions to non-current assets:									
PP&E	159	15	11	107	16	43	—	7	358
Intangibles	3	1	1	—	—	—	—	16	21

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	**2018**	2017	2016
Depreciation and amortization expense on the Consolidated Statements of Earnings (Loss)	**574**	635	601
Depreciation included in fuel and purchased power (Note 6)	**136**	73	63
Depreciation and amortization on the Consolidated Statements of Cash Flows	**710**	708	664

C. Geographic Information

I. Revenues

Year ended Dec. 31	2018	2017	2016
Canada	**1,573**	1,663	1,828
US	**511**	509	450
Australia	**165**	135	119
Total revenue	**2,249**	2,307	2,397

II. Non-Current Assets

	Property, plant and equipment		Intangible assets		Other assets		Goodwill	
As at Dec. 31	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Canada	**4,953**	5,353	**273**	297	**101**	105	**417**	417
US	**657**	619	**59**	25	**50**	43	**47**	46
Australia	**554**	606	**41**	42	**83**	89	**—**	—
Total	**6,164**	6,578	**373**	364	**234**	237	**464**	463

D. Significant Customer

During the year ended Dec. 31, 2018, sales to one customer represented 19 per cent of the Corporation's total revenue (2017 - one customer represented 28 per cent).

Exhibit 1

(Unaudited)

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

To the Financial Statements of TransAlta Corporation

EARNINGS COVERAGE RATIO

The following selected financial ratio is calculated for the year ended Dec. 31, 2018:

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

0.23 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.