CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of February 21, 2020, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2019 and December 31, 2018, the annual information form of Capital Power Corporation for the year ended December 31, 2019 and the cautionary statements regarding forward-looking information which begin on page 48. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation together with its subsidiaries.

In this MD&A, financial information for the years ended December 31, 2019, 2018 and 2017 is based on the audited consolidated financial statements of the Company which were prepared in accordance with Canadian generally accepted accounting principles (GAAP) and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors approved this MD&A as of February 21, 2020.

Contents

FORWARD-LOOKING INFORMATION

Forward-looking information or statements included in this MD&A are provided to inform the Company's shareholders and potential investors about management's assessment of Capital Power's future plans and operations. This information may not be appropriate for other purposes. The forward-looking information in this MD&A is generally identified by words such as will, anticipate, believe, plan, intend, target, and expect or similar words that suggest future outcomes.

Material forward-looking information in this MD&A includes expectations regarding:

- future revenues, expenses, earnings, adjusted EBITDA and adjusted funds from operations,
- the future pricing of electricity and market fundamentals in existing and target markets,
- future dividend growth,
- the Company's future cash requirements including interest and principal repayments, capital expenditures, dividends and distributions,
- the Company's sources of funding, adequacy and availability of committed bank credit facilities and future borrowings,
- future growth and emerging opportunities in the Company's target markets including the focus on certain technologies,
- the timing of, funding of, and costs for existing, planned and potential development projects and acquisitions (including the Cardinal Point Wind project and phase 2 of the Whitla Wind project)
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects, Genesee dual-fuel capability project),
- the impact of market designs on the Company's core markets,
- the impact of the transformation of the Genesee units to 100% dual-fuel, including impacts to adjusted funds from operations, costs of the project, unit capacity and reduction of greenhouse gas emissions,
- expected operational improvements at Genesee resulting from the Genesee Performance Standard program,
- timing of commencing commercial production of carbon nanotubes and expected capital costs of the Genesee Carbon Conversion Centre (see Significant Events),
- expectation of exercising the Company's option to increase its interest in C2CNT,
- expectations pertaining to the financial impacts of Whitla Wind 1 in its first year of operations, including the impacts to adjusted funds from operations and adjusted EBITDA (see Significant Events),
- expectations pertaining to the financial impacts of the acquisition of Goreway (see Significant Events), including the impacts to adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA,
- expectations pertaining to the financial impacts of the swap of interests in the Genesee 3 and Keephills 3 facilities (see Significant Events), including expectations regarding the impacts to adjusted funds from operations,
- expectations around the Company's heat rate call option agreement for Arlington Valley, including impacts to adjusted EBITDA and adjusted funds from operations, and
- expectations around the Line Loss Rule Proceeding including timing of retrospective loss factors being finalized, participation in applicable regulatory processes, and potential impacts to the Company.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate including its review of purchased businesses and assets. The material factors and assumptions used to develop these forward-looking statements relate to:

- electricity and other energy prices and carbon prices,
- performance,
- business prospects (including potential re-contracting of facilities) and opportunities including expected growth and capital projects,
- status of and impact of policy, legislation and regulations,
- effective tax rates,
- other matters discussed under the Performance Overview and Outlook and Targets for 2020 sections,
- results of carbon nanotube concrete testing and preliminary marketing,
- anticipated performance of the acquired Goreway facility,
- anticipated performance of Whitla Wind 1, and
- the anticipated future performance of the Genesee 3 and Keephills 3 facilities used to assess the financial impacts of the swap of interests.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such material risks and uncertainties are:

- changes in electricity prices in markets in which the Company operates,
- changes in energy commodity market prices and use of derivatives,
- regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation,
- generation facility availability and performance including maintenance of equipment,
- ability to fund current and future capital and working capital needs,
- acquisitions and developments including timing and costs of regulatory approvals and construction,
- changes in market prices and availability of fuel,
- ability to realize the anticipated benefits of the Goreway acquisition,
- ability to realize the anticipated benefits of the swap of interests in the Genesee 3 and Keephills 3 facilities,
- limitations inherent in the Company's review of acquired assets, and
- changes in general economic and competitive conditions.

See Risks and Risk Management for further discussion of these and other risks.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the specified approval date. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

OVERVIEW OF BUSINESS AND CORPORATE STRUCTURE

Capital Power is a growth-oriented North American power producer headquartered in Edmonton, Alberta. The Company develops, acquires, owns, and operates power generation facilities using a variety of energy sources. Capital Power owns approximately 6,200 megawatts (MW) of power generation capacity at 26 facilities across North America. Approximately 800 MW of owned generation capacity is in advanced development in Alberta and Illinois.

The Company's power generation operations and assets are owned by Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc., all wholly owned subsidiaries of the Company.

CORPORATE STRATEGY

Capital Power's corporate strategy is based on its vision to power a sustainable future, with our business solutions meeting the evolving electricity needs of society in a responsible and sustainable manner. The corporate strategy comprises the business strategy to operate as a competitive power producer and the financial strategy designed to provide consistent access to low-cost capital. The Company is committed to a position that provides for future dividend growth, an investment-grade credit rating supported by contracted cash flows, and a prudent expansion strategy with a focus on contracted renewable resources and natural gas.

(a) **Geographic focus** – Canada and the U.S. for contracted power generation and Alberta for merchant power generation.

(b) **Technology focus** – large-scale natural gas technologies, renewable wind and solar facilities, with a limited number of technologies and suppliers for each type of generation, as well as carbon conversion technologies.

(c) **Financial strategy** – supportive of the business strategy; intended to provide access to cost competitive capital throughout the business cycle. This is facilitated by maintaining an investment grade credit rating with a stable and growing dividend. This requires a moderate risk profile where price volatility from merchant facilities is balanced with long-term contracted assets and hedging of merchant power price risk through forward sales.

(d) **Operational excellence** – safely manage, operate and maintain its power generation facilities in a manner that optimizes efficiency, productivity and reliability, and minimizes costs while reducing environmental impact and risk.

(e) **Disciplined growth** – restricted to the geographic and technology focuses with specific financial hurdles and rigorous due diligence processes.

(f) **Sustainability** - Capital Power delivers responsible energy for tomorrow by focusing on creating sustainable value for our investors, shareholders, customers and employees in the communities where we operate. Our Environmental, Social and Governance reporting practices are a key pillar of our sustainability strategy, reflecting our belief in the importance of transparency and the resiliency of our business strategy as we transition to a low-carbon economy.

The Company continues to pursue growth in contracted power generation across North America as well as creating additional value in the Alberta market through power generation growth and portfolio trading strategies. During 2019, the Company:

- commenced commercial operation of phase 1 of the Whitla Wind project (Whitla Wind 1),

- commenced construction on the Cardinal Point Wind project (Cardinal Point Wind),
- completed the acquisition of the Goreway facility (see Significant Events),
- entered into a heat rate call option agreement to cover periods outside of Arlington Valley's existing summer tolling agreements (see Significant Events),
- announced an accelerated plan to convert the Genesee facilities to natural gas (see Significant Events), and
- completed the swap of interests in the Genesee 3 and Keephills 3 facilities (see Significant Events).

The Company continues to evaluate acquisition prospects to strengthen its existing portfolio. The Company is also advancing the 100% dual-fuel capability project at the Genesee facility and moving forward with plans to build the Genesee Carbon Conversion Centre for commercial scale production of carbon nanotubes (CNTs). To help ensure that the Company's growth strategy does not compromise its financial condition, it employs hurdle rates of return for acquisition and development project opportunities and evaluates them against the Company's current strategic plan. As part of the Company's growth strategy through developing and building new assets, the Company views power facility construction as a core competency.

PERFORMANCE OVERVIEW

The Company measures its performance in relation to its corporate strategy through financial and non-financial targets that are approved by the Board of Directors of Capital Power. The measurement categories include corporate measures and measures specific to certain groups within the Company. The corporate measures are company-wide and include adjusted funds from operations and safety. The group-specific measures include facility operating margin and other operations measures, committed capital, construction and maintenance capital on budget and on schedule, and facility site safety.

Operational excellence

Performance measure	2019 target	2019 actual results
Facility availability average	95% or greater	94%
Sustaining capital expenditures	$80 to $90 million	$78 million [1]

1 Includes sustaining capital expenditures net of joint venture contributions of $6 million.

The Company's facility availability averaged 94% which reflected planned outages at Genesee, Cloverbar Energy Centre, Joffre, Shepard Energy Centre, York Energy, Goreway, Roxboro, Southport, Decatur Energy, and Arlington Valley. Unplanned outages also occurred at Genesee, Cloverbar Energy Centre, Shepard Energy Centre, Island Generation, Goreway, EnPower, Roxboro, and Southport.

Sustaining capital expenditures were lower than target largely due to lower than expected mine capital spending, scope reductions and cancellation of various projects.

Disciplined growth

Performance measure	2019 target	Status as at December 31, 2019
Whitla Wind 1	Completion of Whitla Wind 1 on budget and on time for commercial operations in December 2019.	Construction completed on time in December 2019. Total project costs are expected to be on budget except for foreign exchange impacts which are partially hedged (see Liquidity and Capital Resources).
Cardinal Point Wind	Progress on the development of Cardinal Point Wind to be on track with budget and the March 2020 completion date.	Construction expected to be complete and on budget (in U.S. dollars) in the first quarter of 2020.
Other contracted growth	$500 million of committed capital.	The Company exceeded its target for other contracted growth through the acquisition of Goreway (see Significant Events).

Financial stability and strength

Performance measure	2019 target [1]	2019 actual results
Adjusted funds from operations [2]	$485 million to $535 million	$555 million
Adjusted EBITDA [2]	$870 million to $920 million	$1,029 million

1 The targets presented at the Company's Investor Day in December 2018 were revised to include the expected impact of the acquisition of Goreway for the periods subsequent to the close of the transaction (see Significant Events).

2 Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures.

OUTLOOK AND TARGETS FOR 2020

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A which identifies the material factors and assumptions used to develop forward-looking information and their material associated risk factors.

At its Investor Day held in December 2019, the Company provided financial guidance for 2020 adjusted funds from operations in the range of $500 million to $550 million and adjusted EBITDA in the range of $935 million to $985 million (see Non-GAAP Financial Measures). The 2020 guidance was based on approximately 63% of the Alberta commercial baseload generation portfolio sold forward at an average contracted price in the mid-$50 per megawatt hour (MWh) range.

Priorities for the Company in 2020 will include supporting our sustainability targets through the development of the Genesee Carbon Conversion Centre (see Significant Events) and the strategic development of natural gas and renewable assets. This includes the advancement of the dual-fuel capability project for the three Genesee units, re-contracting efforts on the Company's facilities and ongoing development of the Company's wind projects. Cardinal Point Wind is expected to commence commercial operations in the first quarter of 2020 and development of phase 2 of the Whitla Wind project (Whitla Wind 2) will proceed in 2020. The Company is targeting additional committed capital of $500 million for contracted growth in 2020.

In 2020, Capital Power's availability target of 93% reflects major scheduled maintenance outages for Genesee 2, Arlington Valley, Decatur Energy, and Southport compared to those scheduled for Genesee 1, Clover Bar Energy Centre, Joffre, Shepard, and Decatur Energy in 2019.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2020, 2021 and 2022 (all as at December 31, 2019) were:

Alberta commercial portfolio positions and power prices	**2020**	**2021**	**2022**
Percentage of baseload generation sold forward [1]	72%	3%	11%
Contracted price [2]	Mid-$50	Mid-$60	Low-$50
Forward Alberta pool prices	$57	$55	$53

1 Based on the Alberta baseload facilities plus a portion of Joffre and the uncontracted portion of Shepard.

2 Forecasted average contracted prices may differ significantly from future average realized prices as future realized prices are driven by a combination of previously contracted prices and settled prices.

The 2020 targets and forecasts are based on numerous assumptions including power and natural gas price forecasts. However, they do not include the effects of potential future acquisitions or development activities, or potential market and operational impacts relating to unplanned facility outages including outages at facilities of other market participants, and the related impacts on market power prices.

At its Investor Day held in December 2019, the Company confirmed its 7% annual dividend growth guidance for 2020 and 2021 and announced a 5% dividend growth guidance for 2022. Each annual increase is subject to changing circumstances and approval by the Board of Directors of Capital Power at the time of the increase.

See Liquidity and Capital Resources for discussion of future cash requirements and expected sources of funding. It is expected that, outside of new growth opportunities, no additional common share equity will be required in 2020.

Performance measure targets for 2020

Performance measure	**2020 target**
Operational excellence	
Facility availability average	93% or greater
Sustaining capital expenditures	$90 to $100 million
Disciplined growth	
Cardinal Point Wind	Completion of Cardinal Point Wind on budget and on time for commercial operations in March 2020.
Whitla Wind 2	Advance development of the Whitla Wind 2 project to be on track with budget and the 2021 completion date.
Other contracted growth	$500 million of committed capital.
Financial stability and strength	
Adjusted funds from operations [1]	$500 million to $550 million
Adjusted EBITDA [1]	$935 million to $985 million

1 Adjusted funds from operations and adjusted EBITDA are non-GAAP financial measures. See Non-GAAP Financial Measures.

NON-GAAP FINANCIAL MEASURES

The Company uses (i) earnings before net finance expense, income tax expense, depreciation and amortization, impairments, foreign exchange gains or losses, finance expense and depreciation expense from its joint venture interests, gains or losses on disposals and unrealized changes in fair value of commodity derivatives and emission credits (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations (AFFO) per share, (iv) normalized earnings attributable to common shareholders, and (v) normalized earnings per share as financial performance measures.

These terms are not defined financial measures according to GAAP and do not have standardized meanings prescribed by GAAP and, therefore, are unlikely to be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, net income attributable to shareholders of the Company, net cash flows from operating activities or other measures of financial performance calculated in accordance with GAAP. Rather, these measures are provided to complement GAAP measures in the analysis of the Company's results of operations from management's perspective.

Adjusted EBITDA

Capital Power uses adjusted EBITDA to measure the operating performance of facilities and categories of facilities from period to period. Management believes that a measure of facility operating performance is more meaningful if results not related to facility operations such as impairments, foreign exchange gains or losses and gains or losses on disposals are excluded from the adjusted EBITDA measure. Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA excludes unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change was made to better align the Company's measure of adjusted EBITDA with its other non-GAAP measures, as both the adjusted funds from operations and the normalized earnings per share measures exclude the impacts of unrealized changes in fair value of commodity derivatives and emission credits. This change also results in improved period over period comparability of adjusted EBITDA.

Comparative figures have been restated to reflect the above change to the adjusted EBITDA metric.

A reconciliation of adjusted EBITDA to net income (loss) is as follows:

(unaudited, $ millions)	Year ended December 31		Three months ended							
	2019	**2018**	**Dec 2019**	**Sep 2019**	**Jun 2019**	**Mar 2019**	**Dec 2018**	**Sep 2018**	**Jun 2018**	**Mar 2018**
Revenues and other income [2]	1,963	1,417	683	517	366	397	340	395	369	313
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(841)	(799)	(309)	(231)	(134)	(167)	(233)	(261)	(152)	(153)
Remove unrealized changes in fair value of commodity derivatives and emission credits included within revenues and energy purchases and fuel	(118)	67	(28)	(8)	(48)	(34)	53	35	(22)	1
Adjusted EBITDA from joint ventures [1]	25	51	6	6	7	6	11	10	12	18
Adjusted EBITDA	**1,029**	**736**	**352**	**284**	**191**	**202**	**171**	**179**	**207**	**179**
Depreciation and amortization [2]	(473)	(335)	(118)	(135)	(122)	(98)	(85)	(83)	(83)	(84)
Unrealized changes in fair value of commodity derivatives and emission credits	118	(67)	28	8	48	34	(53)	(35)	22	(1)
Impairment (see Significant Events)	(401)	-	-	(401)	-	-	-	-	-	-
Gains on acquisition and disposal transactions (see Significant Events)	24	159	24	-	-	-	159	-	-	-
Foreign exchange (loss) gain	(5)	10	-	(1)	-	(4)	6	(2)	3	3
Net finance expense	(156)	(123)	(41)	(42)	(37)	(36)	(33)	(28)	(29)	(33)
Finance expense and depreciation expense from joint ventures [1]	(23)	(32)	(1)	(7)	(7)	(8)	(10)	(7)	(8)	(7)
Income tax recovery (expense) [2]	6	(90)	(63)	66	33	(30)	(19)	(7)	(46)	(18)
Net income (loss)	**119**	**258**	**181**	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**
Net income (loss) attributable to:										
Non-controlling interests	(6)	(7)	(1)	(2)	(2)	(1)	(2)	(1)	(2)	(2)
Shareholders of the Company [2]	125	265	182	(226)	108	61	138	18	68	41
Net income (loss)	**119**	**258**	**181**	**(228)**	**106**	**60**	**136**	**17**	**66**	**39**

1 Total income from joint ventures as per the Company's consolidated statements of income. Prior quarters' values include Capital Power's share of K2 Wind up until the December 31, 2018 disposal date.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Adjusted funds from operations and adjusted funds from operations per share

The Company uses adjusted funds from operations as a measure of the Company's ability to generate cash from its current operating activities to fund growth capital expenditures, debt repayments and common share dividends to the Company's shareholders.

Adjusted funds from operations represents net cash flows from operating activities adjusted to include net finance expense and current income tax expense and exclude changes in operating working capital and distributions received from the Company's joint venture interests. Net finance expense and current income tax expense are included as the timing of cash receipts and payments of interest and income taxes and the resulting cash basis amounts are not comparable from period to period. Changes in operating working capital are excluded from adjusted funds from operations as the timing of cash receipts and payments also affects the period-to-period comparability. Distributions received from the Company's joint venture interests are excluded as the distributions are calculated after the effect of joint venture debt payments, which are not considered operating activities. Adjusted funds from operations is reduced by the tax equity financing project investors' shares of adjusted funds from operations associated with assets under tax equity financing structures to ensure that only the Company's share is reflected in the overall metric. Adjusted funds from operations also excludes the impact of fair value changes in certain unsettled derivative financial instruments that are charged or credited to the Company's bank margin account held with a specific exchange counterparty. Adjusted funds from operations is reduced by sustaining capital expenditures and preferred share dividends and adjusted to include the Company's share of the adjusted funds from operations of its joint venture interests and cash from coal compensation that will be received annually.

Adjusted funds from operations per share is determined by applying adjusted funds from operations to the weighted average number of common shares used in the calculation of basic, diluted and normalized earnings per share.

A reconciliation of net cash flows from operating activities to adjusted funds from operations is as follows:

(unaudited, $ millions)	**Year ended December 31**		**Three months ended December 31**	
	2019	**2018**	**2019**	**2018**
Net cash flows from operating activities per consolidated statements of cash flows	**720**	**450**	**201**	**133**
Add (deduct) items included in calculation of net cash flows from operating activities per consolidated statements of cash flows:				
Interest paid	110	96	27	26
Realized loss on settlement of interest rate derivatives	19	-	-	-
Change in fair value of derivatives reflected as cash settlement	(29)	(21)	7	(5)
Distributions received from joint ventures	(12)	(30)	(3)	(6)
Miscellaneous financing charges paid [1]	6	6	2	2
Income taxes paid	11	2	7	-
Change in non-cash operating working capital	(69)	43	(43)	(19)
	36	96	(3)	(2)
Net finance expense [2]	(123)	(97)	(33)	(25)
Current income tax expense [3]	(14)	(18)	(7)	(3)
Sustaining capital expenditures [4]	(78)	(79)	(20)	(25)
Preferred share dividends paid	(48)	(41)	(12)	(11)
Cash received from coal compensation	50	50	-	-
Remove tax equity interests' respective shares of adjusted funds from operations	(5)	(7)	(1)	(2)
Adjusted funds from operations from joint ventures	17	43	3	15
Adjusted funds from operations	**555**	**397**	**128**	**80**
Weighted average number of common shares outstanding (millions)	**104.3**	**103.0**	**105.3**	**102.3**
Adjusted funds from operations per share ($)	**5.32**	**3.85**	**1.22**	**0.78**

1 Included in other cash items on the consolidated statements of cash flows to reconcile net income to net cash flows from operating activities.

2 Excludes unrealized changes on interest rate derivative contracts, amortization, accretion charges and non-cash implicit interest on tax equity investment structures.

3 Excludes current income tax expense related to the disposal of the Company's interest in the K2 Wind joint venture as the amount is considered an investing activity.

4 Includes sustaining capital expenditures net of partner contributions of $6 million and $1 million for the year and three months ended December 31, 2019, respectively, compared with $8 million and $2 million for the year and three months ended December 31, 2018, respectively.

Normalized earnings attributable to common shareholders and normalized earnings per share

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings (loss) used in the calculation of basic earnings (loss) per share according to GAAP and adjusted for items that are not reflective of performance in the period such as unrealized fair value changes, impairment charges, unusual tax adjustments, gains and losses on disposal of assets or unusual contracts, and foreign exchange gain or loss on the revaluation of U.S. dollar denominated debt. The adjustments, shown net of tax, consist of unrealized fair value changes on financial instruments that are not necessarily indicative of future actual realized gains or losses, non-recurring gains or losses, or gains or losses reflecting corporate structure decisions.

(unaudited, $ millions except per share amounts and number of common shares)	**Year ended December 31**		**Three months ended**							
	2019	**2018**	**Dec 2019**	**Sep 2019**	**Jun 2019**	**Mar 2019**	**Dec 2018**	**Sep 2018**	**Jun 2018**	**Mar 2018**
Basic earnings (loss) per share ($) [2]	**0.73**	**2.17**	**1.61**	**(2.25)**	**0.93**	**0.49**	**1.24**	**0.08**	**0.55**	**0.30**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income (Loss) [2]	**125**	**265**	**182**	**(226)**	**108**	**61**	**138**	**18**	**68**	**41**
Preferred share dividends including Part VI.1 tax	(49)	(42)	(12)	(14)	(12)	(11)	(11)	(10)	(11)	(10)
Earnings (loss) attributable to common shareholders [2]	76	223	170	(240)	96	50	127	8	57	31
Unrealized changes in fair value of derivatives [1]	(81)	67	(28)	(3)	(30)	(20)	35	26	(19)	25
Net loss (gain) on swap transaction (see Significant Events)	192	-	(115)	307	-	-	-	-	-	-
Alberta tax rate change	(51)	-	-	-	(51)	-	-	-	-	-
Gain on disposal of joint venture	-	(134)	-	-	-	-	(134)	-	-	-
Non-cash tax equity adjustment	-	(15)	-	-	-	-	-	-	(15)	-
Realized foreign exchange gain on settlement of foreign currency derivative instruments	-	(29)	-	-	-	-	-	-	-	(29)
Asset held for sale accounting treatment of K2 Wind	-	3	-	-	-	-	3	-	-	-
Income tax adjustments	-	-	-	-	-	-	-	-	(2)	2
Provision for Line Loss Rule Proceeding	4	-	4	-	-	-	-	-	-	-
Normalized earnings attributable to common shareholders [2]	**140**	**115**	**31**	**64**	**15**	**30**	**31**	**34**	**21**	**29**
Weighted average number of common shares outstanding (millions)	104.3	103.0	105.3	106.5	103.6	101.8	102.3	102.4	103.1	104.2
Normalized earnings per share ($) [2]	**1.34**	**1.12**	**0.29**	**0.60**	**0.14**	**0.29**	**0.30**	**0.33**	**0.20**	**0.28**

1 Includes impacts of the interest rate non-hedge held by one of the Company's joint ventures and recorded within income from joint ventures on the Company's statements of income.

2 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Year ended December 31		
	2019	2018	2017
Revenues and other income [3]	1,963	1,417	1,168
Adjusted EBITDA [1, 3]	1,029	736	614
Net income [3]	119	258	125
Net income attributable to shareholders of the Company [3]	125	265	135
Normalized earnings attributable to common shareholders [1, 3]	140	115	104
Basic earnings per share ($) [3]	0.73	2.17	0.98
Diluted earnings per share ($) [2, 3]	0.72	2.16	0.98
Normalized earnings per share ($) [1, 3]	1.34	1.12	1.03
Net cash flows from operating activities	720	450	372
Adjusted funds from operations [1]	555	397	361
Adjusted funds from operations per share ($) [1]	5.32	3.85	3.58
Purchase of property, plant and equipment and other assets	635	355	218
Dividends per common share, declared ($)	1.8550	1.7300	1.6150
Dividends per Series 1 preferred share, declared ($)	0.7650	0.7650	0.7650
Dividends per Series 3 preferred share, declared ($)	1.3633	1.1500	1.1500
Dividends per Series 5 preferred share, declared ($)	1.3095	1.2173	1.1250
Dividends per Series 7 preferred share, declared ($)	1.5000	1.5000	1.5000
Dividends per Series 9 preferred share, declared ($)	1.4375	1.4375	0.5642
Dividends per Series 11 preferred share, declared ($)	0.8960	-	-

	As at December 31		
	2019	2018	2017
Loans and borrowings including current portion	3,413	2,647	2,146
Total assets	8,630	7,569	6,819

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

2 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

3 The comparative periods' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

See Consolidated Net Income and Results of Operations for discussion of the key drivers of the changes in revenues and other income, adjusted EBITDA, net income and net income attributable to shareholders of the Company.

The changes in basic and diluted earnings per share were driven by the same factors as net income which are discussed in Consolidated Net Income and Results of Operations and the changes from period to period in the weighted average number of common shares outstanding. The changes in normalized earnings per share and normalized earnings attributable to common shareholders were affected by the same drivers as basic earnings per share, but also the adjustments between earnings per share and normalized earnings per share described under Non-GAAP Financial Measures.

See Liquidity and Capital Resources for discussion of the key drivers of the changes in net cash flows from operating activities. Adjusted funds from operations for 2019 were higher compared with adjusted funds from operations for 2018, primarily due to higher adjusted funds from operations from the Alberta facilities driven by favorable pricing and generation, adjusted funds from operations from the new facilities acquired and the commissioning of New Frontier Wind in the fourth quarter of 2018. These increases were partially offset by the impact of higher net finance expense and preferred share dividends in 2019 and the impact of the second quarter Alberta contracted facilities outage as described in Consolidated Net Income and Results of Operations.

The increase in purchases of property, plant and equipment and other assets is discussed in Liquidity and Capital Resources.

SIGNIFICANT EVENTS

Capital Power increases its equity interest in C2CNT; testing of carbon nanotubes in concrete proceeding

On December 5, 2019, Capital Power announced plans to build the Genesee Carbon Conversion Centre, the first ever commercial scale production facility of carbon nanotubes at its Genesee facility and plans to exercise its options to increase its equity interest in C2CNT to 40% by the end of 2020.

C2CNT has developed an innovative technology that captures and transforms carbon dioxide into a useful and high-value product called carbon nanotubes which can be used as an additive to help reduce weight and increase the strength in an array of applications including batteries, electronics, sensors, polymer composites and structural materials such as concrete, steel and aluminum. Carbon dioxide emissions are avoided by reducing the amount of material required in addition to the carbon dioxide utilized in the production of CNTs.

The investment supports Capital Power's pursuit of innovative and leading-edge technology to reduce greenhouse gases. The carbon conversion technology, led by Dr. Stuart Licht, head of the C2CNT team and professor of chemistry at George Washington University, is currently being tested at demonstration scale at the Alberta Carbon Conversion Technology Centre located at the Shepard Energy Centre in Calgary that Capital Power co-owns with ENMAX.

Lehigh Hanson, Inc. (Lehigh), a subsidiary of HeidelbergCement A.G., a worldwide construction materials company, has agreed to conduct testing for the utilization of CNTs in concrete at their cost. The testing is currently underway and is expected to be followed by limited marketing of the CNTs in concrete product in the first half of 2020. Lehigh has also made a modest financial contribution to C2CNT development.

Whitla Wind 1 commences commercial operations; Whitla Wind 2 project proceeding

On December 1, 2019, Whitla Wind 1, located in southeast Alberta, began commercial operations. The construction of the 202 MW project was completed on schedule and on budget within its $315 million to $325 million target, except for foreign exchange impacts (see Liquidity and Capital Resources). Whitla Wind 1 is expected to provide adjusted EBITDA of $27 million and AFFO of $17 million in its first full year of operation.

The Company also announced that it is moving forward with the second phase of the Whitla Wind facility that will add 97 MW in 2021. Capital Power will leverage its construction experience from Whitla Wind 1 to deliver Whitla Wind 2 with an expected capital cost of $165 million.

Whitla Wind 2 will generate carbon credits that can be used to hedge against Capital Power's carbon compliance costs from its Alberta thermal generation facilities. Capital Power is in active discussions with commercial and industrial customers for renewable offtake contracts from Whitla Wind 2.

Accelerated plan for Genesee natural gas capability

During 2019, the Company announced that it is proceeding with a project that will maximize the flexibility to utilize natural gas as fuel at Genesee, which previously burned primarily coal. The total cost of the project to completely transform the Genesee units to dual-fuel capability is estimated at $70 million with expenditures of $10 million incurred in 2019 and expected costs of $43 million, and $17 million in 2020 and 2021, respectively. The project involves adding new gas pipeline infrastructure within the Genesee site and modifications to the Genesee 1 and 2 boilers. The rated capacity of the units will remain the same.

After the units have been transformed to 100% dual-fuel capability, the units can utilize up to 100% natural gas or coal, or a mix of the two. The amount of coal used at any given time, versus natural gas, will be driven by several factors including natural gas and coal prices and carbon costs.

Based on 100% dual-fuel capability, annual greenhouse gas emissions (GHGs) would be reduced by approximately 25% to 45%, if operation of the units is between 50% to 100% of hours on natural gas.

The Genesee facility will have dual-fuel capability up to December 2029 and will continue as a 100% natural gas-fired facility after that time. The Genesee units are already the most efficient coal generating units in Alberta and best performing from an emissions intensity perspective. Under the Genesee Performance Standard program, which commenced in 2016, a 12% improvement in efficiency and performance of the units is targeted by 2021, which improvements will benefit both natural gas and coal operations.

$275 million medium-term note issuance

On November 8, 2019, the Company issued $275 million of unsecured medium-term notes due in 2030 with interest payable semi-annually at 4.424% commencing on August 8, 2020. The net proceeds of the offering were used to repay indebtedness under the Company's credit facilities and for general corporate purposes.

Genesee 3 and Keephills 3 swap transaction

On August 2, 2019, the Company announced it had entered into an agreement to divest its 50% share of Keephills 3 to TransAlta Corporation (TransAlta), and to acquire TransAlta's 50% share of Genesee 3. The transaction closed on October 1, 2019, with a net cost to Capital Power of $10 million, net of nominal working capital and other closing adjustments. Previously both facilities had been owned and operated under 50/50 Joint Venture Agreements between Capital Power and TransAlta. Following the close of the transaction, Genesee 3 is fully owned and operated by Capital Power and Keephills 3 is fully owned and operated by TransAlta.

Keephills 3 and Genesee 3 are the only supercritical coal facilities in Alberta, with a net capacity of 463 MW and 466 MW, respectively. The swap of interests in the facilities is aligned with Capital Power's strategic plan to deliver responsible energy for tomorrow. As a result of the transaction, the Company gained full control of the Genesee site, providing strategic freedom and latitude to make decisions that further optimize value for the Genesee units. The transaction is expected to streamline costs and commercial processes and reduce regulatory compliance risk.

The transaction resulted in a pre-tax net loss of $249 million. In the third quarter of 2019, the Company recorded a pre-tax impairment of $401 million on Keephills 3 upon classification as assets held for sale. In the fourth quarter of 2019, the acquisition of the additional 50% of Genesee 3 was accounted for as a business combination. A gain of $24 million was recognized upon close of the transaction driven by the remeasurement of the Company's existing share of Genesee 3. In addition, the net reduction to the carrying amounts of the Company's coal-fired generation assets resulted in a one-time adjustment of $128 million to accelerate the recognition of deferred government grant revenue that aligns with the reduction in the new lower carrying amount of coal-fired assets. This is related to the government grant revenue that the Company is receiving over time from the province of Alberta for the 2029 phase-out of coal-fired generation. The Off-coal Agreement was not impacted by the transaction and as a result, compensation will continue to be collected over time and the Company's ongoing obligations pertaining to the Off-coal Agreement are unchanged. The transaction is expected to be neutral to AFFO over the medium term.

Capital Power updates plans for President and Chief Executive Officer role

On July 29, 2019, the Company announced that Brian Vaasjo, President and Chief Executive Officer, had advised the Board of Directors of his intention to retire in 2020.

The announcement activated an established Chief Executive Officer succession plan developed by Capital Power's Board of Directors. The Board's search for a new President and Chief Executive Officer was conducted through the remainder of 2019 and into early 2020, with the intention that the Board would announce a successor in due course. On February 24, 2020, the Company announced that Brian Vaasjo will remain as President and Chief Executive Officer of the Company for an additional three years.

Dividend increase

On July 26, 2019, the Company's Board of Directors approved an increase of 7.3% in the annual dividend for holders of its common shares, from $1.79 per common share to $1.92 per common share. This increased common share dividend commenced with the third quarter 2019 quarterly dividend payment on October 31, 2019 to shareholders of record at the close of business on September 30, 2019.

$325 million private placement debt financing

On June 12, 2019, the Company issued $325 million of private placement senior notes which consist of three tranches with 10, 12 and 15-year terms. The 10-year tranche has a principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The 12-year tranche has a $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year tranche has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%. The net proceeds from the transaction will primarily be used for refinancing of existing bank indebtedness and for other general corporate purposes.

Acquisition of the Goreway Power Station

On June 4, 2019, the Company completed the acquisition of 100% of the ownership interests in Goreway Power Station Holdings Inc., which owns the Goreway Power Station (Goreway). Goreway is an 875 MW natural gas combined cycle generation facility located in Brampton, Ontario. The purchase price consisted of (i) $405 million of total cash consideration, including working capital and other closing adjustments of $18 million, and (ii) the assumption of $590 million of project level debt.

Financing of the Goreway acquisition consisted of a combination of debt from the Company's existing credit facilities and equity offerings as described below.

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario Independent Electricity System Operator (credit ratings of A (high)/Aa3 from DBRS and Moody's, respectively). Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy and fully meets the Company's investment criteria. In addition, the investment contributes to the Company's dividend growth strategy through immediate AFFO accretion supported by contracted cash flows through mid-2029.

Goreway is expected to generate approximately $124 million of adjusted EBITDA and $50 million of AFFO in 2020. For the 2020-2023 period, average annual adjusted EBITDA and AFFO are estimated to be $127 million and $56 million, respectively. The acquisition of Goreway is forecasted to be $0.27 accretive to AFFO per share in 2020 representing growth of approximately 6%.

Preferred share offering

On May 16, 2019, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series 11 (Series 11 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $5 million. The preferred shares will pay fixed cumulative dividends of $1.4375 per share per annum, yielding 5.75% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the Board of Directors of Capital Power, for the initial period ending June 30, 2024. The dividend rate will be reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that, in any event, such rate shall not be less than 5.75%. The Series 11 Shares are redeemable by Capital Power, at its option on June 30, 2024 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 11 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter. Holders of the Series 12 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 4.15%, as and when declared by the Board of Directors of Capital Power. The Series 12 Shares would be redeemable by Capital Power, at its option, on June 30, 2029 and June 30 of every fifth year thereafter at a value of $25.00 per share. The Series 12 Shares would also be redeemable by Capital Power, at its option, on any date after June 30, 2024 excluding June 30 of every fifth year, at a value of $25.50 per share.

Common share offering

In May of 2019, the Company completed a public offering of 4,945,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $30.30 per Subscription Receipt, for total gross proceeds of $150 million less issue costs of $7 million (inclusive of the full exercise of a 645,000 over-allotment option). On June 4, 2019, upon closing of the Goreway acquisition, each Subscription Receipt was converted for one common share of the Company.

Appointments to the Board of Directors

Effective April 26, 2019, Robert Phillips was appointed to the Capital Power Board of Directors.

Effective March 1, 2019, Jane Peverett was appointed to the Capital Power Board of Directors.

Heat rate call option at Arlington Valley

During the first quarter of 2019, the Company entered into a heat rate call option agreement (HRCO) with an investment grade counterparty covering the periods outside of Arlington Valley's existing summer tolling agreements. The HRCO commenced on April 1, 2019 and terminates December 31, 2025, covering (i) April and November-December 2019 and (ii) January-May and October-December 2020-2025. Pursuant to the HRCO the counterparty has the right to call the plant in exchange for fixed monthly premiums plus reimbursements for fuel at an indexed price, variable operating and maintenance expense and start charges. Adjusted EBITDA and AFFO from the Arlington Valley facility during the period covered by the HRCO are expected to be consistent with the guidance provided at the time the acquisition was announced.

SUBSEQUENT EVENT

Approval of normal course issuer bid

Subsequent to the end of 2019, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.5 million of its outstanding common shares during the one-year period from February 26, 2020 to February 25, 2021.

FACILITIES AND PORTFOLIO OPTIMIZATION

Facility category and facility	Type of generating facility	Year commissioned	Capacity (MW) Facility	Capacity (MW) Capital Power interest	Revenues based on [2]	Contract expiry
Alberta commercial facilities [1]						
Genesee 3 [3]	Coal and natural gas co-fired	2005	516	516	Merchant	-
Keephills 3 [3]	Supercritical coal-fired	2011	516	-	Merchant	-
Clover Bar Energy Centre 1, 2 and 3	Natural gas-fired simple cycle	2008 (Unit 1) 2009 (Units 2 and 3)	243	243	Merchant	-
Joffre	Natural gas-fired combined cycle cogeneration	2001	480	192	Merchant (mid-merit)	-
Shepard	Natural gas-fired combined cycle	2015	860	430	Merchant with tolling agreement for 50% of owned capacity	2035 (tolling agreement)
Halkirk	Wind turbine	2012	150	150	Merchant with renewable energy credits (RECs) sold under fixed price agreement	2032 (RECs)
Clover Bar Landfill Gas	Landfill gas-fired	2005	5	5	Merchant with emission credits purchased by Capital Power from the City of Edmonton	-
Alberta contracted facilities [1]						
Genesee 1	Coal and natural gas co-fired	1994	430	430	Capacity and output sold under PPA to Alberta Balancing Pool	2020
Genesee 2	Coal and natural gas co-fired	1989	430	430	Capacity and output sold under PPA to Alberta Balancing Pool	2020
Whitla Wind 1	Wind turbine	2019	202	202	Fixed price contract with the Alberta Electric System Operator	2039
Ontario and British Columbia contracted facilities						
Island Generation	Natural gas-fired combined cycle	2002	275	275	PPA with BC Hydro	2022
York Energy	Natural gas-fired simple cycle	2012	400	200	Energy supply contract with Independent Electric System Operator (IESO)	2032
East Windsor	Natural gas-fired cogeneration	2009	84	84	Energy supply contract with IESO	2029
Goreway	Natural gas-fired combined cycle	2009	875	875	Energy supply contract with IESO	2029
Kingsbridge 1	Wind turbine	2001 and 2006	40	40	Energy supply contracts with IESO	2026
Port Dover and Nanticoke	Wind turbine	2013	105	105	Energy supply contract with IESO	2033
Quality Wind	Wind turbine	2012	142	142	Electricity purchase agreement (EPA) with BC Hydro	2037
Savona [4]	Waste heat	2008	5	5	EPA with BC Hydro	2028
150 Mile House [4]	Waste heat	2008	5	5	EPA with BC Hydro	2028
U.S. contracted facilities						
Roxboro, North Carolina	Solid fuels [5]	1987	46	46	PPA with Duke Energy Progress Inc.	2021
Southport, North Carolina	Solid fuels [5]	1987	88	88	PPA with Duke Energy Progress Inc.	2021
Decatur Energy, Alabama	Natural gas-fired combined cycle	2002	825	825	Tolling agreement with Tennessee Valley Authority	2022
Arlington Valley, Arizona	Natural gas-fired combined cycle	2002	580	580	Tolling agreements with Arizona Public Service Company and HRCO with an investment grade counterparty	2025
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA with Duke Energy Progress, LLC	2030

Facility category and facility	Type of generating facility	Year commissioned	Capacity (MW) Facility	Capacity (MW) Capital Power interest	Revenues based on [2]	Contract expiry
Bloom Wind, Kansas	Wind turbine	2017	178	178	Fixed price contract with Allianz Risk Transfer	2027
Macho Springs, New Mexico	Wind turbine	2011	50	50	PPA with Tucson Electric Power	2031
New Frontier, North Dakota	Wind turbine	2018	99	99	Fixed price contract with Morgan Stanley Capital Group	2030

1 Management has determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one cash generating unit (CGU) for impairment testing purposes (see Use of Judgments and Estimates). Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

2 Certain of the Company's facilities derive revenues under PPAs.

3 On October 1, 2019, the Company divested its 50% share of Keephills 3 and, in exchange, acquired TransAlta's 50% share of Genesee 3 (see Significant Events).

4 For operational reporting, the Company combines Savona and 150 Mile House waste heat facilities together as a single entity referred to as EnPower.

5 Solid fuels at Roxboro and Southport include wood residuals, tire-derived fuels and coal.

Facility category and facility	Type of generating facility	Year to be commissioned	Capacity (MW) Facility	Capacity (MW) Capital Power interest	Revenues based on	Contract expiry
Under construction or in advanced development						
Cardinal Point Wind	Wind turbine	2020	150	150	Fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output	2032
Whitla Wind 2	Wind turbine	2021	97	97	In discussions for potential offtake contracts	-
Genesee 4 and 5	Natural gas-fired combined cycle	To be determined [1]	1,060	530	Merchant with approximately 250 MW contracted to ENMAX for an initial term of 8 years	To be determined

1 Contingent on future Alberta electricity demand requiring the addition of new generation.

Portfolio optimization

Capital Power's commodity portfolio is comprised of generation assets, customer positions and trading positions. All commodity risk management and optimization activities are centrally managed by Capital Power's commodity portfolio management group. Portfolio optimization includes activities undertaken to manage Capital Power's exposure to commodity risk and enhance earnings. Overall commodity exposure within the portfolio is managed within limits established under Capital Power's risk management policies.

Capital Power manages its output from its commercial and contracted facilities with residual commodity exposure on a portfolio basis. Capital Power sells and/or buys physical and/or financial forward contracts that are non-unit specific, to reduce exposure to facility specific availabilities. Capital Power also takes positions in environmental commodity markets outside of Alberta to develop capability to support Capital Power's growth strategy and to generate trading profits.

CONSOLIDATED NET INCOME AND RESULTS OF OPERATIONS

The primary factors contributing to the change in consolidated net income for 2019 compared with 2018 are presented below followed by further discussion of these items.

(unaudited, $ millions)		
Consolidated net income for the year ended December 31, 2018 [1]		**258**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial facilities and portfolio optimization	79	
Alberta contracted facilities	(12)	
Ontario and British Columbia contracted facilities	39	
U.S. contracted facilities	71	
Corporate	116	293
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits		185
Impairment		(401)
Decrease in gains on acquisition and disposal transactions (see Significant Events)		(135)
Increase in depreciation and amortization expense		(138)
Increase in foreign exchange loss		(15)
Decrease in finance expense and depreciation expense from joint ventures		9
Increase in net finance expense		(33)
Decrease in income before tax		(235)
Change in income tax expense or recovery		96
Decrease in net income		**(139)**
Consolidated net income for the year ended December 31, 2019		**119**

1 The comparative periods' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Results by facility category and other

	Year ended December 31							
	2019	2018	2019	2018	2019	2018	2019	2018
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions) [13]		**Adjusted EBITDA** (unaudited, $ millions) [3, 13]	
Total electricity generation, average facility availability and facility revenues	24,527	20,229	94	95	1,525	1,222		
Alberta commercial facilities [4]								
Genesee 3 [5]	2,509	1,814	99	92	132	88		
Keephills 3 [5]	1,353	1,831	95	98	72	93		
Clover Bar Energy Centre 1, 2 and 3	1,043	860	92	89	69	59		
Joffre	774	609	93	95	66	53		
Shepard Energy Centre	2,928	2,938	91	92	140	136		
Halkirk	442	450	98	97	43	41		
Clover Bar Landfill Gas	-	-	-	21	-	-		
Alberta commercial facilities	9,049	8,502	94	93	522	470		
Portfolio optimization	N/A	N/A	N/A	N/A	203	117		
	9,049	8,502	94	93	725	587	307	228
Alberta contracted facilities [4]								
Genesee 1	3,044	3,268	92	100	118	140		
Genesee 2	3,167	2,959	99	94	140	128		
Whitla Wind 1 [6]	77	N/A	97	N/A	3	N/A		
	6,288	6,227	95	97	261	268	191	203
Ontario and British Columbia contracted facilities								
Island Generation	721	27	98	100	38	39		
York Energy [7]	16	10	98	98	N/A	N/A		
East Windsor	11	9	99	99	35	35		
Goreway [8]	537	N/A	89	N/A	119	N/A		
K2 Wind [9]	N/A	222	N/A	99	N/A	3		
Kingsbridge 1	105	103	98	98	9	9		
Port Dover and Nanticoke	294	299	97	98	44	44		
Quality Wind	354	362	97	96	46	47		
EnPower	23	38	79	96	2	3		
	2,061	1,070	94	98	293	180	232	193
U.S. contracted facilities								
Roxboro, North Carolina	324	327	94	96	38	37		
Southport, North Carolina	459	439	90	92	67	61		
Decatur Energy, Alabama	2,145	2,703	93	95	87	88		
Arlington Valley, Arizona [10]	2,934	87	95	94	154	7		
Beaufort Solar, North Carolina	29	27	99	96	3	2		
Bloom Wind, Kansas	717	711	99	98	44	94		
Macho Springs, New Mexico	132	127	98	98	16	15		
New Frontier, North Dakota [11]	389	9	96	98	40	-		
	7,129	4,430	94	95	449	304	247	176
Corporate [12]					188	58	52	(64)
Unrealized changes in fair value of commodity derivatives and emission credits					47	20		
Consolidated revenues and other income and adjusted EBITDA					**1,963**	**1,417**	**1,029**	**736**

1 Gigawatt hours (GWh) of electricity generation reflects the Company's share of facility output.

2 Facility availability represents the percentage of time in the period that the facility was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

3 The financial results by facility category, except for adjusted EBITDA, were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

4 Based on the nature of future cash flows, the Alberta assets are combined as one CGU for impairment testing purposes. Since the cash flows of Genesee 1 and 2 will remain contracted through 2020, management will continue to present facility results based on the Alberta Commercial and Alberta Contracted groupings through 2020.

5 On October 1, 2019, the Company divested its 50% share of Keephills 3 and, in exchange, acquired TransAlta's 50% share of Genesee 3 (see Significant Events).

6 Phase 1 of Whitla Wind was commissioned on December 1, 2019.

7 York Energy is accounted for under the equity method. Capital Power's share of the facility's net income is included in income from joint ventures on the Company's consolidated statements of income. Capital Power's share of the facility's adjusted EBITDA is included in adjusted EBITDA above. The equivalent of Capital Power's share of the facility's revenue was $31 million for 2019, compared with $30 million for 2018. The facility's revenues are not included in the above results.

8 Goreway was acquired on June 4, 2019.

9 Capital Power's share of K2 Wind was disposed of effective December 31, 2018.

10 Arlington Valley was acquired on November 30, 2018.

11 New Frontier Wind was commissioned on December 21, 2018.

12 Corporate revenues were offset by interplant category eliminations.

13 The prior periods' amounts for the Ontario and British Columbia contracted facilities, as appropriate, have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Energy prices and hedged positions

		Year ended December 31	
Alberta	**Unit**	**2019**	**2018**
Hedged position [1]	Percentage sold forward at beginning of year (%)	78	87
Spot power price average	$ per MWh	55	50
Realized power price [2]	$ per MWh	57	51
Natural gas price (AECO) [3]	$ per gigajoule (Gj)	1.87	1.46

1 Hedged position is for the Alberta baseload plants as well as a portion of Joffre and the uncontracted portion of Shepard.

2 Realized power price is the average price realized as a result of the Company's commercial contracted sales and portfolio optimization activities.

3 AECO refers to the historical virtual trading hub located in Alberta and known as the NOVA Inventory Transfer system operated by TransCanada Pipelines Limited.

Alberta commercial facilities and portfolio optimization

The Alberta spot price averaged $55 per MWh in 2019, compared to $50 per MWh in 2018. The increase in spot prices in 2019 reflected the impact of higher natural gas pricing as well as unseasonably cold temperatures coupled with baseload facility outages experienced during the first quarter of the year.

Generation and availability for the year ended December 31, 2019 were higher than the corresponding period in 2018 primarily due to higher dispatch at Clover Bar Energy Centre and Joffre, despite a longer planned outage at Joffre in 2019 compared with 2018, and more frequent unplanned outages at Keephills 3 in 2019 compared with 2018. Higher generation and availability for the year ended December 31, 2019 was also driven by the Genesee 3 and Keephills 3 swap transaction (see Significant Events) as Genesee 3 performed above expectations after the close of the transaction and did not experience a planned outage in the fourth quarter of 2019 compared with a significant planned outage that occurred primarily in the fourth quarter of 2018.

Revenues and other income were higher for the year ended December 31, 2019 compared to 2018, primarily due to higher realized power prices and increased generation as described above.

Adjusted EBITDA for the year ended December 31, 2019 increased compared to 2018 as a result of the revenues and other income drivers noted above. Additionally, there were higher margins earned on export activity and on sales of emission credits than in 2018. Partially offsetting these favourable variances were the impact of higher natural gas pricing on fuel purchases, increased carbon costs, lower ancillary services revenue and higher transmission expenses as compared to 2018.

Alberta contracted facilities

Availability for 2019 was lower compared with 2018 primarily due to the length of the Genesee 1 planned maintenance outage in 2019, which was longer than the Genesee 2 planned outage in 2018. Despite the length and timing of the 2019 planned outage, generation for the year ended December 31, 2019 was consistent with 2018 due to lower dispatch by the PPA buyer for Genesee 1 and 2 in 2018, compared with 2019.

Revenues and other income were lower for the year ended December 31, 2019 compared to 2018 primarily due to the noted planned outage length as the 2019 results reflect higher net availability penalties which were magnified by higher Alberta power pool prices during the outage period in 2019. The variance also reflects higher excess energy payments driven by higher generation and higher running energy payments on higher pricing, partially offset by lower capacity revenues compared with 2018.

Adjusted EBITDA was lower in 2019 compared with 2018, primarily due to the noted factors affecting revenues and other income, as well as higher coal costs in 2019. These unfavourable variances were partially offset by higher environmental compliance incentive recoveries in 2019 compared with 2018.

Ontario and British Columbia contracted facilities

Generation was higher in 2019 compared with 2018 primarily due to the acquisition of Goreway (see Significant Events) in the second quarter of 2019 and higher dispatch at Island Generation in 2019, partially offset by the sale of K2 Wind in the fourth quarter of 2018. Availability in 2019 was lower than 2018 primarily due to unplanned outages at the EnPower facilities, as well as the impact on overall availability of a Goreway planned outage in 2019.

Revenues and other income were higher in 2019 compared with 2018 primarily due to the acquisition of Goreway in the second quarter of 2019 (see Significant Events). Adjusted EBITDA was higher in 2019 compared with 2018 primarily due to the Goreway acquisition (see Significant Events), partially offset by the disposal of K2 Wind in the fourth quarter of 2018. Revenues and other income do not include K2 Wind and York Energy, which are accounted for under the equity method, with the exception of distribution income received from K2 Wind following its classification as an asset held for sale, at which time equity accounting ceased and distributions were no longer recorded against the equity investment.

U.S. contracted facilities

Generation increased for the year ended December 31, 2019 compared with 2018 primarily due to the addition of Arlington Valley in the fourth quarter of 2018 and the commencement of commercial operations at New Frontier Wind in the fourth quarter of 2018, partially offset by lower dispatch at Decatur Energy.

Availability for 2019 decreased compared to 2018 primarily due to a longer planned outage at Decatur Energy in 2019 compared with 2018 and more frequent unplanned outages at Southport and Roxboro in 2019 compared with 2018. This was partially offset by the noted additions of Arlington Valley and New Frontier Wind which had strong availability in 2019.

Revenues and other income and adjusted EBITDA were higher in 2019 compared with 2018 primarily due to the addition of Arlington Valley and the commencement of commercial operations at New Frontier Wind in 2018, partially offset by the impacts of the updated Bloom Wind tax equity investor agreement signed during the second quarter of 2018.

Corporate

Corporate results include (i) revenues for cost recoveries and other income related to coal compensation from the Province of Alberta, (ii) costs of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management, and environment, health and safety, and (iii) business development expenses. Note that cost recovery revenues are primarily intercompany revenues that are offset by interplant category transactions.

Adjusted EBITDA for 2019 was higher compared with 2018 primarily as a result of the accelerated recognition of coal compensation revenue recognized on the swap of interests in Genesee 3 and Keephills 3 (see Significant Events). This was partially offset by an increase in the provision for the Line Loss Rule proceeding related to the noted swap of interests and the write-off of wind development projects no longer being developed.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Year ended December 31			
	2019	**2018**	**2019**	**2018**
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Income before tax**	
Unrealized (losses) gains on Alberta power derivatives	(19)	79	20	(5)
Unrealized gains (losses) on U.S. energy derivatives	67	(51)	67	(51)
Unrealized (losses) gains on natural gas derivatives	-	(10)	33	(16)
Unrealized (losses) gains on emission derivatives	(1)	2	(1)	2
Unrealized (losses) gains on emission credits held for trading	-	-	(1)	3
	47	**20**	**118**	**(67)**

The Company's revenues and other income and adjusted EBITDA relating to its Alberta commercial facilities and portfolio optimization and U.S. wind facilities include realized changes in the fair value of commodity derivatives and emission credits. Unrealized changes in the fair value of commodity derivatives and emission credits are excluded from revenues and other income relating to the Alberta commercial facilities and portfolio optimization and U.S. wind facilities and are also excluded from the Company's adjusted EBITDA metric.

When a derivative instrument settles, the unrealized fair value changes recorded in prior periods for that instrument are reversed from this category. The gain or loss realized upon settlement is then reflected in adjusted EBITDA for the applicable facility category.

Unrealized gains on the Alberta power portfolio of $20 million recognized by the Company in 2019 were primarily due to the impact of increasing forward prices on net forward purchase contracts not designated as cash flow hedges, partially offset by the reversal of prior period unrealized net gains on positions that settled during the year. During the comparable period in 2018, the Alberta power portfolio recognized unrealized losses of $5 million primarily due to the reversal of prior period unrealized net gains on positions that settled during the year as well as the impact of decreasing forward prices on future positions.

During the year ended December 31, 2019, the Company recorded unrealized gains of $67 million on U.S. energy derivatives, due to the impact of decreasing forward prices on the value of forward sales contracts associated with the Bloom Wind, New Frontier Wind and Cardinal Point Wind facilities. During the comparable period in 2018, unrealized losses on U.S. energy derivatives of $51 million were attributable to the impact of increasing forward prices on the value of forward sales contracts associated with the Bloom Wind, New Frontier Wind and Cardinal Point Wind facilities.

Unrealized gains on natural gas derivatives of $33 million recognized in 2019 were due to the impact of increasing forward natural gas prices on net forward purchase contracts, as well as the reversal of prior period unrealized losses on purchase contracts that settled during the year. During the comparable period in 2018, unrealized losses of $16 million reflected the impact of decreasing forward natural gas prices on net forward purchase contracts, partially offset by the reversal of prior period unrealized losses on purchase contracts that settled during the year.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Year ended December 31	
	2019	**2018**
Interest on borrowings less capitalized interest	(133)	(110)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	1	11
	(132)	(99)
Other finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(24)	(24)
Total net finance expense	(156)	(123)
Impairments	(401)	-
Depreciation and amortization	(473)	(335)
Foreign exchange (loss) gain	(5)	10
Gains on acquisition and disposal transactions (see Significant Events)	24	159
Finance expense and depreciation expense from joint ventures	(23)	(32)
Income tax recovery (expense)	6	(90)
Net loss attributable to non-controlling interests	6	7

Net finance expense

Higher net finance expense for the year ended December 31, 2019 compared with the prior year was primarily due to higher loans and borrowings outstanding as a result of the acquisition of Arlington Valley in the fourth quarter of 2018 and the financing related to the acquisition of Goreway in the second quarter of 2019 (see Significant Events).

Impairments

During the year ended December 31, 2019, the Company recognized a pre-tax impairment of $401 million related to the classification of Keephills 3 as an asset held for sale prior to its divestiture (see Significant Events).

Depreciation and amortization

Depreciation and amortization for the year ended December 31, 2019 increased compared with the prior year primarily due to the acquisition of Arlington Valley and New Frontier Wind commencing commercial operation in the last quarter of 2018 and the acquisition of Goreway in the second quarter of 2019 (see Significant Events). In addition to this, starting in the first quarter of 2019, Capital Power adjusted the useful lives of assets related to coal to reflect new expected end of life dates resulting from federal regulation changes, including the assets that would be used in a coal-to-gas conversion, to the new estimated life as set out by the federal government. Slightly offsetting these impacts was the net lower depreciation resulting from the swap of interests in Genesee 3 and Keephills 3 (see Significant Events).

Foreign exchange (loss) gain

Foreign exchange losses for 2019 are mostly attributable to the impact of the strengthening of the Canadian dollar relative to the U.S. dollar on the Company's forward U.S. dollar purchase contracts which were settled during 2019.

Foreign exchange gains for 2018 are primarily driven by the impact of the weakening of the Canadian dollar relative to the U.S. dollar on the Company's forward U.S. dollar purchase contracts.

Gains on acquisition and disposal transactions

During the year ended December 31, 2019, the Company recognized a pre-tax gain of $24 million on the swap of interests in Genesee 3 and Keephills 3 (see Significant Events).

On December 31, 2018, the Company disposed of its minority owned interest of 90 MW in K2 Wind and recorded a pre-tax gain of $159 million.

Finance expense and depreciation expense from joint ventures

Finance expense and depreciation expense from joint ventures includes Capital Power's share of finance expense and depreciation expense of York Energy and K2 Wind (through to the December 31, 2018 disposal date), which are accounted for under the equity method. Equity accounting ceased for K2 Wind during the fourth quarter of 2018 when it was classified as an asset held for sale.

Income tax recovery (expense)

In 2019, the Company recorded an income tax recovery of $6 million compared with an income tax expense of $90 million in 2018. The change is primarily due to the recognition of a deferred income tax recovery on the impairment of Keephills 3 in the third quarter of 2019 (see Significant Events), the decrease in the Alberta corporate income tax rate in the second quarter of 2019, the reversal of a deferred tax expense on the Company's investment in a subsidiary following the disposal of Keephills 3 in the fourth quarter of 2019, and lower amounts attributable to tax-equity interests. This was partially offset by the recognition of a deferred income tax expense on the one-time adjustment to accelerate the recognition of deferred government grant revenue following the swap of interests in Genesee 3 and Keephills 3 in the fourth quarter of 2019 (see Significant Events).

With the introduction of the Bill 3 – Job Creation Tax Act on June 28, 2019, the Alberta corporate income tax rate was reduced from 12% to 8% over four years. Since the Canadian deferred tax assets and liabilities were re-measured, a deferred income tax recovery of $51 million was recognized during the second quarter of 2019.

Non-controlling interests

Non-controlling interests mostly consist of the Coal Mine partner's share of the consolidated depreciation expense of the Coal Mine.

COMPREHENSIVE INCOME

(unaudited, $ millions)	Year ended December 31	
	2019	**2018**
Net income	119	258
Other comprehensive (loss) income:		
Net unrealized (losses) gains on derivative instruments	(26)	15
Net unrealized gains on derivative instruments – joint ventures	-	3
Net realized losses on derivative instruments reclassified to net income	9	14
Net realized losses on derivative instruments reclassified to net income – joint ventures	-	2
Unrealized foreign exchange (loss) gain on the translation of foreign operations	(39)	50
Actuarial (loss) gain related to the Company's defined benefit pension plan	(6)	2
Losses realized in net income on disposal of joint venture	-	12
Total other comprehensive (loss) income, net of tax	(62)	98
Comprehensive income	**57**	**356**

Other comprehensive (loss) income includes fair value adjustments on financial instruments held by the Company to hedge market risks and which meet the requirements of hedges for accounting purposes. To the extent that such hedges are ineffective, any related gains or losses are recognized in net income. Other unrealized fair value changes on derivative instruments designated as cash flow hedges and foreign currency translation gains or losses are subsequently recognized in net income when the hedged transactions are completed and the foreign operations are disposed of or otherwise terminated.

FINANCIAL POSITION

The significant changes in the consolidated statements of financial position from December 31, 2018 to December 31, 2019 were as follows:

(unaudited, $ millions)	As at December 31							
	2019	2018	Increase (decrease)	IFRS 16 impact (see Accounting Changes)	Acquisition through business combination [2]	Impact of G3/K3 swap transaction [3]	Other	Primary other changes
Trade and other receivables [1]	334	438	(104)	(2)	22	(1)	(123)	Lower receivables are driven by the receipt of the remaining proceeds on disposal of K2 Wind and timing of collection of generation receivables.
Right-of-use assets	95	-	95	86	-	-	9	Reclassification from property, plant and equipment and additions less depreciation.
Intangible assets	760	473	287	-	498	(79)	(132)	Decrease due largely to amortization and emission credits used for compliance.
Property, plant and equipment [1]	6,089	5,356	733	-	814	(312)	231	Increase due to capital additions, including Whitla Wind 1 and Cardinal Point Wind, partly offset by depreciation and foreign exchange impacts.
Net derivative financial instruments liabilities	64	45	19	-	104	-	(85)	Primarily due to the impacts of increasing forward prices on forward natural gas purchase contracts and decreasing forward prices on forward power sales for U.S. contracted wind facilities, offset partly by the impacts of increasing forward prices on forward Alberta power sales contracts.
Loans and borrowings (including current portion)	3,413	2,647	766	-	590	-	176	Increase primarily due to issuance of private placement senior notes (see Significant Events) and medium-term notes (see Significant Events), partly offset by net repayments of various loans and borrowings.

(unaudited, $ millions)	As at December 31		Increase (decrease)	IFRS 16 impact (see Accounting Changes)	Acquisition through business combination [2]	Impact of G3/K3 swap transaction [3]	Other	Primary other changes
	2019	2018						
Deferred revenue and other liabilities (including current portion)	443	649	(206)	(4)	-	(156)	(46)	Decrease mainly driven by amortization of deferred government grant revenue.
Provisions (including current portion)	457	345	112	-	40	1	71	Increase mainly due to additional decommissioning liabilities incurred for development projects and revisions to existing decommissioning provisions.
Lease liabilities (including current portion)	111	18	93	96	-	-	(3)	Decrease primarily due to lease payments, partially offset by the addition of land leases for Whitla Wind 1.
Net deferred tax liabilities[1]	488	351	137	(2)	206	(58)	(9)	Decrease primarily due to the impact of the reduced Alberta statutory income tax rate and the reclass of tax on the disposal of K2 Wind from deferred tax liability to current tax liability, which was partially offset by the utilization of non-capital loss carry forwards and an increase in taxable temporary differences that will reverse in the future.

[1] Balance as at December 31, 2018 has been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

[2] Includes the impact of assets and liabilities acquired through the Goreway acquisition (see Significant Events).

[3] Includes the net impact of assets and liabilities acquired and disposed of through the Genesee 3 and Keephills 3 swap transaction (see Significant Events).

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2019**	**2018**	**Change**
Operating activities	720	450	270
Investing activities	(866)	(554)	(312)
Financing activities	218	233	(15)

Operating activities

Cash flows from operating activities increased compared with 2019 due to higher EBITDA before non-cash items (including non-cash tax equity attributes, changes in non-cash operating working capital and the Company's share of adjusted EBITDA from joint ventures). These increases were partially offset by higher interest paid due to additional loans and borrowings, realized losses on the settlement of interest rate derivative instruments during 2019 and lower distributions received from joint ventures driven by the disposal of K2 Wind in 2018.

Investing activities

Cash flows used in investing activities for the year ended December 31, 2019 increased compared with the same period in 2018 primarily due to the acquisition of Goreway in the second quarter of 2019 (see Significant Events) as compared to the acquisition of Arlington Valley during 2018, combined with higher capital expenditures, including higher spend on Whitla Wind 1 and Cardinal Point Wind in 2019 compared to spending on New Frontier Wind in 2018, and lower proceeds on disposal of the K2 Wind joint venture received in 2019 as compared to 2018.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2018 actual	Year ended December 31 2018 actual	2019 actual	2020 estimated [1,2]	Actual or projected total [2]	Timing
Genesee 4 & 5 [3,4]	18	-	-	-	700	Targeted completion currently being reassessed by management
New Frontier Wind [5]	20	154	3	-	177	Completed in December 2018
Whitla Wind 1 [6]	3	68	251	17	339	Completed in December 2019
Cardinal Point Wind [7]	2	26	228	71	327	Targeted completion March of 2020
Whitla Wind 2	-	-	-	60	165	Targeted completion in the fourth quarter of 2021
Commercial initiatives [8]	5	11	65	90	241	
Development sites and projects	9	6	5	-		
Subtotal growth projects		**265**	**552**	**238**		
Sustaining – plant maintenance excluding Genesee mine		73	74			
Sustaining – Genesee mine maintenance and lands		14	10			
Total capital expenditures [9]		**352**	**636**			
Emission credits held for compliance		5	12			
Investment in C2CNT		3	-			
Capitalized interest		(5)	(13)			
Purchase of property, plant and equipment and other assets		**355**	**635**			

1 The Company's 2020 estimated capital expenditures include only expenditures for previously announced growth projects and exclude other potential new development projects.

2 Projected capital expenditures to be incurred over the life of the projects for Genesee 4 and 5, New Frontier Wind, Whitla Wind 1, Cardinal Point Wind, Whitla Wind 2, and commercial initiatives are based on management's estimates. Projected capital expenditures for development sites are not reflected beyond the current period until specific projects reach the advanced development stage.

3 Excludes interest to fund construction and refundable transmission system contribution payments.

4 Continuation and timing of the Genesee 4 and 5 project will be considered once new generation is required in Alberta to balance supply and demand.

5 New Frontier Wind began commercial operations in December 2018. The finalization of construction activities occurred during 2019. The total cost excludes a $19 million (US$15 million) developer fee paid to a subsidiary of the Company.

6 The original projected total construction cost for Whitla Wind 1 was expected to be in the range of $315 million to $325 million. Actual project costs are now expected to exceed that range driven by foreign exchange impacts on U.S. dollar costs. These amounts were partially economically hedged by forward U.S. currency purchase derivatives which settled in the year ended December 31, 2019 resulting in realized foreign exchange gains of $8 million recorded in net income. The remaining foreign exchange differential is driven by movements in the U.S dollar to Canadian dollar foreign exchange rate between the bid date of Whitla Wind 1 into the initial Alberta Renewable Electricity Program and the date that Whitla Wind 1 was awarded the contract, which were not hedged.

7 The projected total cost for Cardinal Point Wind exceeds the expected range of construction costs of $289 million to $301 million (US$236 million to US$246 million) driven by foreign exchange rate impacts. The projected total cost in U.S. dollars is US$246 million and is within the expected range.

8 Commercial initiatives include the combustion turbine upgrade project for Decatur Energy with capital expenditures incurred to the end of December 31, 2019 of $32 million (US$24 million). This project resulted in an additional 30 MW of generation and was completed in the second quarter of 2019. Commercial initiatives also includes expected spending on the Company's Genesee dual-fuel project (see Significant Events) and the Genesee Performance Standard project as well as various other projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

9 Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the consolidated statements of cash flows as purchase of property, plant and equipment and other assets.

Financing activities

The cash flows from financing activities for the year ended December 31, 2019 primarily reflected the net issuance of loans and borrowings in the year, issuance of common and preferred shares (see Significant Events), repurchase of common shares under the Company's normal course issuer bid, and payment of common and preferred share dividends. Cash flows from financing activities for 2019 decreased compared with 2018 most notably due to realized gains on settlement of foreign exchange derivatives in 2018 and higher dividends paid in 2019, offset partially by higher net funds received from the issue, net of repayments and repurchases, of shares and loans and borrowings in 2019 as compared to 2018.

The Company's credit facilities consisted of:

(unaudited, $ millions)		**As at December 31, 2019**			**As at December 31, 2018**		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
Committed credit facilities	2024	1,000			1,150		
Letters of credit outstanding			50			99	
Bankers' acceptances outstanding			-			396	
Bank loans outstanding [1]			319			218	
		1,000	369	631	1,150	713	437
Bilateral demand credit facilities	N/A	430			200		
Letters of credit outstanding			189			172	
		430	189	241	200	172	28
Demand credit facilities	N/A	25	-	25	25	-	25
		1,455	**558**	**897**	**1,375**	**885**	**490**

1 U.S. dollar denominated bank loans outstanding totaling US$246 million (December 31, 2018 – US$160 million).

As at December 31, 2019, the committed credit facility utilization decreased $344 million compared with the utilization as at December 31, 2018, due to the Company's other loans and borrowings issuances during the year. In the second quarter of 2019, the $1 billion of committed credit facilities were extended one year to mature in July 2024. In the third quarter of 2019, the Company secured $100 million of additional Canadian bilateral demand credit facilities, and an additional US$50 million in U.S. bilateral demand credit facilities were secured in each of the third and fourth quarters of 2019. The available credit facilities provide the Company with adequate funding for ongoing development projects.

The Company has a corporate credit rating of BBB- with a stable outlook from Standard & Poor's (S&P). The BBB rating category assigned by S&P is the fourth highest rating of S&P's ten rating categories for long-term debt obligations. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments, however, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

The Company has a corporate credit rating of BBB (low) with a stable outlook from DBRS Limited (DBRS). The BBB rating category assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality and the capacity of the payment of financial obligations is considered acceptable but the entity is vulnerable to future events.

The above credit ratings from S&P and DBRS are investment grade credit ratings which enhance Capital Power's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Capital Power's loan and credit agreements require the Company to meet certain financial covenants as described below:

Financial covenant	Required at the end of each fiscal quarter	Actual as at December 31, 2019
Modified consolidated net tangible assets to consolidated net tangible assets ratio [1]	Not less than 0.75 to 1.0	0.88
Consolidated senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.55
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	3.48

1 As defined in the relevant agreements.

2 Only in the event that Capital Power is assigned a rating of less than BBB- by S&P and less than BBB (low) by DBRS.

Future cash requirements

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's expected cash requirements for 2020 include:

(unaudited, $ millions)	2020 expected cash requirements
Repayment of debt payable [1, 2]	310
Capital expenditures – sustaining	92
Capital expenditures – ongoing growth projects	148
Capital expenditures – commercial initiatives	90
Common share dividends [3]	206
Preferred share dividends	52

1 Excludes repayment of credit facilities.

2 Assumes refinancing of $559 million of Goreway unsecured senior debt due in 2020. The bank facility was extended to January 2027 subsequent to year end.

3 Includes 7% annual dividend growth, subject to approval by the Board of Directors of Capital Power.

The Company uses a short-form base shelf prospectus to provide it with the ability, market conditions permitting, to obtain new debt and equity capital from external markets when required. Under the short-form base shelf prospectus, Capital Power may raise up to $3 billion by issuing common shares, preferred shares, subscription receipts exchangeable for common shares and/or other securities of the Company and/or debt securities. This prospectus expires in June 2020.

If the Canadian and U.S. financial markets become unstable, Capital Power's ability to raise new capital, to meet its financial requirements, and to refinance indebtedness under existing credit facilities and debt agreements may be adversely affected. Capital Power has credit exposure relating to various agreements, particularly with respect to its PPA, energy supply contract, trading and supplier counterparties. While Capital Power continues to monitor its exposure to its significant counterparties, there can be no assurance that all counterparties will be able to meet their commitments.

Off-statement of financial position arrangements

As at December 31, 2019, the Company has $239 million of outstanding letters of credit for collateral support for trading operations, conditions of certain service agreements and to satisfy legislated reclamation requirements. If the Company were to terminate these off-statement of financial position arrangements, the penalties or obligations would not have a material impact on the Company's financial condition, results of operations, liquidity, capital expenditures or resources.

Capital resources

(unaudited, $ millions)	As at December 31	
	2019	**2018**
Loans and borrowings	3,413	2,647
Lease liabilities [1]	111	18
Less cash and cash equivalents	(248)	(182)
Net debt	3,276	2,483
Share capital	3,441	3,200
Deficit and other reserves [2]	(377)	(190)
Non-controlling interests	37	43
Total equity	3,101	3,053
Total capital	**6,377**	**5,536**

1 Includes the current portion disclosed within deferred revenue and other liabilities.

2 Balance as at December 31, 2018 has been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

CONTRACTUAL OBLIGATIONS, CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

(unaudited, $ millions)	Payments due by period						
	2020	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Loans and borrowings [1, 2]	824	315	17	17	787	1,246	3,206
Interest on loans and borrowings	134	101	92	91	85	213	716
Trade and other payables [3]	282	-	-	-	-	-	282
Lease liabilities	10	9	9	9	9	113	159
Capital – growth projects [4]	142	101	-	-	-	-	243
Capital – commercial initiatives [5]	90	70	-	-	-	-	160
Additional investment in C2CNT	26	-	-	-	-	-	26
Decommissioning provisions [6]	4	5	38	4	4	435	490
Energy purchase and transportation contracts [7]	189	80	44	44	44	446	847
Operating and maintenance contracts	60	65	55	38	35	217	470
Environmental credits [8]	30	-	2	-	6	6	44
Commodity and other derivative liabilities net of financial assets	-	-	-	3	2	8	13
Total	**1,791**	**746**	**257**	**206**	**972**	**2,684**	**6,656**

1 Repayments of loans and borrowings exclude fair value differentials of $19 million related to debt assumed on previous asset acquisitions and $213 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

2 Payments on loans and borrowings for 2020 include $559 million of Goreway unsecured senior debt due in September 2020. Subsequent to year end, the Company extended the bank facility to January 2027.

3 Excluding accrued interest on loans and borrowings of $19 million.

4 Capital Power's obligations for capital – growth projects in future periods include Cardinal Point Wind, Whitla Wind 2, the finalization of construction activities for Whitla Wind 1, and expected spend on other development sites and projects in 2020. Obligations for 2021 include expected spend for Whitla Wind 2. These obligations exclude interest to fund construction of $10 million and refundable transmission system contribution payments.

5 Capital Power's obligations for capital – commercial initiatives in future periods include the combustion turbine upgrade project for Decatur Energy, the Genesee dual-fuel project (see Significant Events), the Genesee Performance Standard project, and various other projects designed to either increase the capacity or efficiency of their respective facilities or to reduce emissions.

6 Capital Power's decommissioning provisions reflect the undiscounted cash flows required to settle obligations for the retirement of its generation facilities and the Genesee Coal Mine.

[7] Energy purchase and transportation contracts include natural gas transportation contracts which are based on estimates that are subject to changes in regulated rates for transportation and natural gas purchase contracts. The estimates for natural gas purchase contracts are subject to changes in expected consumption levels, and have expiry terms ranging from 2020 to 2037.

[8] Future environmental credits purchases are presented net of future environmental credits sales.

Contingent liabilities

The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

Other legal matters

In each of 2017, 2018, and 2019, the Government of Alberta (GoA) withheld approximately $2.7 million from the Company's annual off-coal payment, on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amount and specific performance for future payments. Similarly, the GoA amended its Linear Property Assessment Guidelines in 2017 to eliminate the anticipated cessation of coal emissions (and related business closures) from being considered in property tax assessments, which erroneously suggests that the off-coal payments were intended to compensate the Company for non-net book value related costs. Capital Power has also commenced litigation on the basis that this provision discriminatorily applies only to three coal generators.

Line Loss Rule Proceeding provision

Capital Power participated in the Line Loss Rule (LLR) Proceeding before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding addressed the replacement of the non-compliant LLR as well as the possible correction of line loss charges and credits for the years 2006 up to and including 2016.

The Company is participating in legal or regulatory processes rendering the final outcome of the LLR Proceeding still unknown. However, based on current AUC decisions, Capital Power would incur additional charges related to historical periods and, as such, has recorded a provision of $15 million pertaining to the estimated net liability for its currently held Alberta assets. The recorded provision reflects the Company's estimated net liability. It is expected that the invoicing process will result in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recovered from the appropriate parties. Though the Alberta Electric System Operator had indicated that invoicing for the line loss adjustments would not occur until 2021, it is now seeking an order from the AUC to accelerate and commence the invoicing process in 2020. Until such an order is granted, however, no change in invoice timing is expected. As a result, the estimated net liability is recorded as a non-current provision at December 31, 2019. Upon closing of the acquisition of the additional 50% interest in Genesee 3 and divestiture of the Company's interest in Keephills 3 (see Significant Events) on October 1, 2019, the Company recorded a $6 million increase to the provision in the fourth quarter of 2019, which increased the previously recorded provision of $9 million. The increase in the provision is a result of Genesee 3 being an older asset which therefore has greater exposure to the retroactive line loss adjustments.

RISKS AND RISK MANAGEMENT

The Company's approach to risk management is to identify, monitor and manage the key controllable risks facing the Company and to consider appropriate actions to respond to uncontrollable risks. Risk management includes the controls and procedures for reducing controllable risks to acceptable levels and the identification of the appropriate actions in cases of events occurring outside of management's control. Acceptable levels of risk are established by the Board of Directors of Capital Power and govern the Company's decisions and policies associated with risk. The Board of Directors of Capital Power reviews the Company's risk profile on a bi-annual basis and material changes to the risk profile as required.

Capital Power employs an Enterprise Risk Management Program (ERM Program) to identify, evaluate, report and monitor key risks that may affect the achievement of the Company's strategic and related business objectives. During 2019 the ERM Program was updated to align with the Committee of Sponsoring Organization's (COSO) standard for risk management, COSO Enterprise Risk Management – Integrated Framework, which was released in 2017. Previously, the ERM Program aligned with the International Organization for Standardization's (ISO) ISO 31000. The change from the ISO to COSO framework did not result in significant changes to the ERM Policy and the Company continues to undertake risk assessment in conjunction with core corporate business strategy and planning processes.

Risk management at Capital Power is carried out at several levels and is subject to the oversight of the Board of Directors of Capital Power. The President and Chief Executive Officer has ultimate accountability for managing the Company's risks and approves the framework for enterprise risk management. The President and Chief Executive Officer as well as the rest of the executive team provide general oversight and policy reviews and recommendations, meeting periodically to review enterprise risk management performance and to evaluate significant or emerging risks.

The Vice President of Risk Management and Internal Audit is responsible for the enterprise risk management framework, including developing risk management policies and processes and monitoring the Company's compliance with said policies and processes by performing periodic reviews and internal audits. They are also responsible for the leadership of the commodity and credit risk management (middle office) function, security and contingency planning, as well as insurance risk management. Individual executive risk owners are accountable for carrying out the risk management and mitigation activities associated with the risks in their respective operations. All Capital Power employees are expected to understand the risks that fall within their areas of responsibility and to manage these risks within approved risk tolerances.

Management views risk management as an ongoing process and continually looks for ways to enhance the Company's risk management framework.

Capital Power's principal risk factors could have an adverse impact on the Company's business, prospects, financial condition, results of operations, cash flow, liquidity, capital expenditures, or resources. Not only do these risks provide Capital Power with exposure to negative consequences but also to the possibility that positive consequences will be missed. The identified risk factors are interdependent and the potential impact of any one factor is generally difficult to quantify as the impact of other risk factors changes at the same time or at a subsequent time. These principal risk factors are discussed below:

Climate change risk

Capital Power has prepared an assessment of climate-related risks and opportunities to conform with the recommendations of the Task Force on Climate-related Financial Disclosure. This involved exploring the resulting risks and opportunities of three different scenarios, including scenarios with both favourable and unfavourable outcomes, and one of which was a scenario in which global temperatures are reduced to limit the global temperature increase to 2 degrees Celsius (or lower) above pre-industrial levels. This document can be accessed on the Company's website via the following link: https://www.capitalpower.com/2019-capital-power-climate-change-disclosure-report-tcfd.

Environmental risk discussion is incorporated across this and other subsections of this Risk and Risk Management section including legal, regulatory and stakeholder risk, people risk, operation and maintenance of equipment and systems risk, extreme natural and other unexpected occurrences, energy supply risk, and reputation risk.

Climate change will be the primary theme driving the industry in which Capital Power operates for the foreseeable future. Deep decarbonization initiatives therefore represent a significant opportunity for power generation and Capital Power.

As such, the risks, opportunities, and environmental compliance obligations associated with climate change and decarbonization have been directly integrated into Capital Power's annual business strategy and planning process. The Company has assessed which technologies could prevail in the short, medium and long term under various scenarios. Capital Power intends to evolve with the power market and ensure that the Company's generation portfolio is an optimal mix of low cost, reliability and low carbon.

Strategies employed for managing climate change risk:

- Portfolio evolution to lower emitting and renewable assets resulting in a lower greenhouse gas compliance obligations.
- Development of significant expertise in the development and construction of renewables facilities.
- Active compliance cost management via an active presence in environmental commodity markets.
- Regular engagement with government bodies to participate in the development of carbon policy.
- Proactive pursuit of opportunities to enhance the reliability and efficiency of the Company's renewables facilities.
- Development of the Genesee Performance Standard program targeting efficiency and performance improvements to both natural gas and coal operations.
- Development of expertise and the investment in carbon capture and utilization technology, such as C2CNT.

Over the short and medium term, Capital Power will continue to focus on growing renewable and natural gas opportunities in Canada and the U.S., and transitioning fuel at existing facilities from coal to natural gas or renewable sources. Capital Power anticipates a continual evolution towards carbon free generation through the medium and long term. The intention is to monitor technologies in the short term and potentially pursue these new technologies in the medium and long term if they align with our competencies.

Legal, regulatory and stakeholder risk

Capital Power is subject to risk associated with changing political conditions and with changes in federal, provincial, state, or local laws and regulations or common law and their interpretation by relevant authorities. It is not possible to predict with complete accuracy all changes in the legislative and regulatory environment or their impact on the Company's business, operations, or the markets in which the Company operates.

Capital Power is required to maintain numerous licenses, permits and governmental approvals for the development, construction and operation of its projects and participation in its markets. If Capital Power fails to satisfy the conditions of these instruments, there could be an adverse impact on the effectiveness and cost of those projects or operations. Many of the regulatory approval processes for the development, construction and operation of power generation facilities require stakeholder input. Accordingly, progress in Capital Power's development, construction and operational activities could be impeded by stakeholder intervention. Changes in law and regulatory requirements may also adversely impact the market dynamics for Capital Power, the participation levels of counterparties that Capital Power relies on to support its portfolio optimization strategies and the costs associated with participating in these markets.

Capital Power's assets are emitters of various air pollutants including CO_2, NO_x, SO_2, mercury, and particulate matter. Accordingly, Capital Power's operations are subject to extensive environmental laws, regulations and guidelines relating to the generation and transmission of electricity, pollution and protection of the environment, health and safety, air emissions, water usage, wastewater discharges, hazardous material handling and storage, treatment and disposal of waste and other materials, remediation of sites, and land-use responsibility.

These regulations can impose a liability for costs to investigate or remediate contamination. Compliance with new regulatory requirements may require Capital Power to incur significant capital expenditures, additional operating expenses or cause operations at certain facilities to end prior to the end of their economic life; failure to comply with such regulations could result in fines, penalties or the curtailment of operations. Further, there can be no assurance that compliance with or changes to environmental regulations will not materially adversely impact Capital Power's business prospects, financial condition, operations or cash flow.

The Company is subject to requirements around minimizing the impact to wildlife at its wind facilities. Capital Power complies with all regulatory requirements which include completing pre-disturbance bird and bat studies and post-construction bird and bat monitoring programs.

Capital Power's ability to develop new projects is also affected by the availability of transmission and distribution systems. If restrictive transmission price regulation is imposed, transmission companies may not have sufficient incentive to invest in expansion of the transmission infrastructure. In addition, the Alberta power market has a number of existing transmission connections to neighbouring external markets. Any material expansion of those existing interconnections, or the creation of new interconnections could have a material adverse impact on Capital Power's business in Alberta. Capital Power cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

See Regulatory Matters for further discussion of current regulatory items.

Strategies employed for managing legal, regulatory and stakeholder risk:

- Predict and identify existing, new or changed laws or regulations, or changed interpretations of such, and prepare appropriate responses or plans.
- Comply with all applicable laws, regulations and guidelines and monitor compliance.
- Perform environmental compliance audits and take corrective actions as necessary.
- Establish positive relationships with relevant levels of government, agencies and stakeholders.
- Participate in all relevant consultation processes. Execute on-time permitting, license renewals and other activities associated with laws and regulations.
- Proactively identify environmental risks within operations, maintenance and construction activities and promote awareness throughout and at all levels of the Company.
- Ensure that contractors align with Capital Power's environmental policies and procedures.
- Support the timely development of appropriate transmission capability through active relationships with regulators and government.

Power price risk

The market price for electricity, in the jurisdictions and markets in which Capital Power operates, affects Capital Power's revenues. Capital Power buys and sells some of its electricity in the Alberta wholesale market and such transactions are settled at spot market prices. Market electricity prices are dependent upon a number of factors including: the projected supply and demand of electricity, the bidding strategy of other generators offering electricity in Alberta, the asset management plans of the Balancing Pool, the price of raw materials that are used to generate electricity, the cost of complying with applicable environmental and other regulatory requirements, the structure of the particular market, and weather conditions. Natural gas price levels may impact power prices in the markets that the Company participates in. It is not possible to predict future electricity prices with certainty, and electricity price volatility could therefore have a material effect on Capital Power.

Electricity sales associated with the PPA for Genesee 1 and 2 are accounted for as long-term fixed margin contracts, which limits the impact of swings in wholesale electricity spot prices, unless plant availability drops significantly below the PPA target availability for an extended period. Electricity sales and steam sales associated with the Joffre facility located at the Nova Chemicals Company (NOVA) petrochemical complex are subject to market price variability as there are provisions in the contract with NOVA that require the facility to run to provide steam to the host facility, irrespective of market prices. Although the Company's Genesee 3 plant is not covered by a long-term commercial contract, it is a baseload coal-fired generating plant with relatively low variable costs that generally runs when it is available. For the Company's Genesee 3, Clover Bar Energy Centre, Halkirk, Joffre and Shepard facilities, spot electricity prices affect profitability.

Capital Power uses derivative instruments, including futures, forwards, options and swaps, to manage its power price and financial market risks inherent in its electricity generation operations. These activities, although intended to mitigate price volatility, expose Capital Power to other risks. When Capital Power sells power forward, it gives up the opportunity to sell power at potentially higher prices in the future. Selling forward may also result in losses if the underlying price to provide replacement power, in the event of an outage, turns out to be greater than the contract price. In addition, Capital Power purchases and sells electricity-based contracts for merchant trading purposes. In the future, Capital Power could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodity.

Capital Power is exposed to market risks through its power marketing business, which involves the sale of energy, capacity and related products, and the purchase and sale of fuel, transmission services and emission allowances. These market risks primarily include volatility arising from location and from timing differences that may be associated with buying and transporting fuel, converting fuel into energy and delivering the energy to a buyer.

When aggregate customer electricity consumption (load shape) changes unexpectedly, Capital Power is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is higher during peak hours when people and organizations are most active; conversely, consumption is lower during off-peak hours at night or early morning.

Strategies employed for managing power price risk:

- The Risk Oversight Council (consisting of the senior management representatives appointed by the President and Chief Executive Officer) establishes the overall direction, structure, conduct and control of Capital Power's commodity exposure management activities, both in physical and financial derivatives markets.
- Execute the Company's growth strategy and re-contract generation facilities under new or extended contracts to maintain a balance of contracted and non-contracted facilities.
- Limit exposure to market price volatility by entering into long-term power contracts on certain of our generation units. Examples include contracts-for-differences, and back-to-back physical and financial contracts to lock in a margin.
- Maintain a commodity risk management program which provides the infrastructure to manage commodity and trading risks associated with the commodity business.
- Take market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors.
- Report monthly key risk measures in relation to applicable limits to the executive team with quarterly review by the Board of Directors of Capital Power.
- Perform regular commodity portfolio stress testing to observe the effects of plausible scenarios taking into account historical price movements and certain hypothetical extreme events.
- Minimize exposure to extreme price fluctuations, especially during higher priced peak hour periods. To do this, Capital Power relies on historical load shape data provided by load settlement agents and local distribution companies to anticipate what the aggregate customer electricity consumption will be during peak hours. When consumption varies from historical consumption patterns and from the volume of electricity purchased for any given peak hour period, Capital Power is exposed to prevailing market prices because it must either buy electricity if it is short or sell electricity if it is long. Such exposures can be exacerbated by other events such as unexpected generation facility outages and unusual weather patterns.
- Limit exposure to spot price variability within specified risk limits by entering into various purchase and sale arrangements for periods of varying duration. Due to limited market liquidity and the variability of electricity consumption between peak hours and off-peak hours, it is not possible to hedge all positions every hour. The Company operates under specific policy limits, such as total commodity risk and stop-loss limits, and generally trades in electricity to reduce the Company's exposure to changes in electricity prices or to match physical or financial obligations.

Fuel supply and price risk

Capital Power requires energy from sources such as coal, natural gas, wind, wood waste, tire derived fuel (TDF) and the sun to generate electricity. A disruption in the supply or a significant increase in the price of any supplies required by Capital Power could have a material adverse impact on Capital Power's business, financial condition and results of operations. The price of energy supply is dependent upon a number of factors, including: the supply and demand for fuel supplies, the quality of the fuel, the cost of complying with applicable environmental and other regulatory requirements, and transportation costs. In the case of natural gas, prices are also influenced by weather conditions, storage inventory levels, drilling levels and production, imports and general economic conditions. Changes in any of these factors could increase Capital Power's cost of generating electricity or decrease Capital Power's revenues due to production cutbacks.

The Genesee units have partial dual-fuel capability with 100% capability expected by 2021. By 2021 these units will have the flexibility to utilize up to 100% natural gas or coal, or a mix of the two, and will exclusively burn natural gas after coal is phased out on December 31, 2029. The dual-fuel transformation of the Genesee units introduces a greater degree of exposure to AECO natural gas prices than Capital Power has seen in the past. Accordingly, natural gas price volatility could have a significant impact on the Company's cost of generating electricity, particularly after 2029. Coal for the Genesee units is supplied under long-term agreements where the price is based on a cost-of-service model with annual updates for inflation, interest rate and capital budget parameters and is therefore not subject to coal market price volatility. A shortage of coal supply resulting from significant disruption of the coal mine equipment and operation could negatively impact generation and revenues from these plants.

Capital Power's natural gas-fired plants that are operated as merchant facilities are susceptible to the risks associated with the volatility of natural gas prices. Natural gas purchases for these power plants are made under variable price contracts and when a facility's heat rate (a measure of fuel efficiency) does not meet expectations, unit profitability is affected. Our risk exposure to variable natural gas pricing for Arlington, Decatur Energy, East Windsor, Goreway, Island Generation, and York Energy is substantially or fully mitigated by their long term PPAs. The facilities at Southport and Roxboro operate using a fuel mixture of wood waste, TDF, and a small amount of coal. Coal is sourced with regional coal suppliers, while the TDF and wood residuals are supplied under long-term agreements.

Capital Power uses derivative instruments for merchant trading purposes and to manage its natural gas and emission allowances and financial market risks inherent in its electricity generation operations to mitigate price volatility. In the future, Capital Power could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities.

Capital Power's wind and solar power facilities are dependent on the availability and constancy of sufficient wind and solar resources to meet projected capacity factors. Fluctuations in wind speed or duration, as well as hours of sunlight could have a material negative impact on revenues for these facilities in any year.

Strategies employed for managing fuel supply and price risk:

- The strategies described in power price risk above, such as the Risk Oversight Council, commodity risk management program, corporate governance over market positions and key risk measures and commodity portfolio stress testing also apply to natural gas risk.
- Establish long-term supply agreements.
- Establish long-term fixed transportation agreements.
- Maintain coal stock-pile inventories.
- Establish contracts with fuel cost flow-through provisions, where possible.
- Limit exposure to market price volatility by entering into long-term natural gas contracts on certain of our generation units. Examples include contracts-for-differences, and back-to-back physical and financial contracts to lock in a margin.
- Actively participate on the Genesee Coal Mine Joint Venture Committee and exercise contractual rights as required.
- Development of the Genesee Performance Standard program targeting efficiency and performance improvements to both natural gas and coal operations.
- Manage greenhouse gas compliance obligations via an active presence in environmental commodity markets.
- Thorough research and collection of wind and solar data prior to development or acquisition of facilities.
- Keep apprised of new technology that may increase generation by capturing more wind or sun.

Operation and maintenance of equipment risk

Power facilities operations are susceptible to outages due to failure of generation equipment, transmission lines, pipelines or other equipment, which could make the impacted facility unavailable to generate electricity.

The inability of Capital Power's generation facilities to generate the expected amount of electricity to be sold under contract or to the applicable market could have a significant adverse impact on the Company's revenues. In addition, counterparties to PPAs have remedies available to them if Capital Power fails to operate facilities in accordance with contract requirements, including the recovery of damages and termination of contractual arrangements. To the extent that facility equipment requires significant capital and other operation and maintenance expenditures to maintain efficiency, requires longer than forecast down-times for maintenance and repair, experiences outages due to equipment failure or suffers disruptions of power generation for other reasons, Capital Power's cost of generating electricity will increase and its revenues may be negatively affected. As an adopter of new technology, Capital Power can be exposed to design flaws or other issues, the impacts of which may not be covered by warranties or insurance. The failure of Capital Power's facilities to operate at required capacity levels may result in the facilities having their contracted capacity reduced and, in certain cases, Capital Power having to make payments on account of reduced capacity to power purchasers.

The terms of the PPAs for owned facilities provide appropriate incentives to facility owners to keep the facilities well maintained and operational. They also provide force majeure protection for high-impact, low-probability events including major equipment failure.

Many of Capital Power's generation facilities operate under PPAs or other similar contracts which are subject to a number of risks. PPA contracts contain performance benchmarks that must be achieved and other obligations that must be complied with by Capital Power. Capital Power may incur charges in the event of unplanned outages or variations from the contract performance benchmarks. PPAs expire at various times and there can be no assurance that a subsequent PPA will be available or, if available, that it will be on terms, or at prices that permit the operation of the facility on a profitable basis.

Capital Power depends on transmission facilities owned and operated by external parties to deliver the wholesale power from its power generation facilities to its customers. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, there may be a material adverse effect on Capital Power’s ability to sell and deliver wholesale power.

Strategies employed for managing operation and maintenance of equipment risk:

- Establish long-term service agreements with original equipment manufacturers on key assets including access to replacement components to limit down time in the event of a unit failure.
- Ensure constructive relationships with original equipment manufacturers.
- Execute appropriate operating and maintenance practices (reliability program) to minimize the likelihood of prolonged unplanned down time for the Company’s facilities.
- Maintain an inventory of strategic spare parts which can reduce down time in the event of failure.
- Employ a root cause analysis program to ensure that problems are properly identified and addressed and that learnings are shared across the fleet.
- Establish and maintain appropriate business interruption, property, and boiler and machinery insurance to reduce the impact of prolonged outages caused by insured events.
- Ensure operations and sustainment projects are properly resourced with qualified and trained staff and contractors.

Cybersecurity and systems risk

Capital Power’s ability to carry out its normal business processes is dependent on the performance and security of the key information and operational technology systems that support its core operations. Cyberattacks are possible and, if successful, could result in the loss or misuse of sensitive information and have significant adverse impacts on the Company’s general operations. Failure of any key information and operational technology systems, during or after implementation, could result in significant lost revenues, increased costs or regulatory fines.

Strategies employed for managing cybersecurity and systems risk:

- Establish and maintain disaster recovery and backup plans to ensure systems and processes can be recovered in the event of a cyberattack.
- Regular monitoring of the Company’s information and operational technology systems, logs and security events.
- Regular communication with external governmental and industry groups to share threat intelligence, trend analysis, and best practices.
- Periodic external audits of the effectiveness of the Company’s information and operational technology security systems.
- System safeguards to combat the ever-increasing sophistication in phishing attacks.
- End user awareness training.
- Ensure critical assets meet all North American Electric Reliability Corporation Critical Infrastructure Protection standards, based on each respective asset’s categorization and the applicable regulatory region’s requirements.
- Minimize the customization of commercial software, monitor impacts on processes and internal controls and undertake remedial actions, if required.
- Ensure implementation projects are properly resourced with qualified and trained staff and contractors.
- Employ change management to ensure all enhancements are fully tested and approved, prior to production deployment.
- The Cybersecurity Leadership Council, comprised of senior leaders from various areas of the Company, meets regularly to monitor the effectiveness of the strategies above and to address new and evolving risks.

People risk

Capital Power’s ability to continuously operate its facilities and grow the business is dependent upon attracting, retaining and developing sufficient labour and management resources. Capital Power is experiencing a demographic shift as a significant number of its employees are expected to retire over the next several years. Failure to secure sufficient qualified labour may negatively impact Capital Power’s operations or construction and development projects, or may increase expenses. Capital Power’s current collective bargaining agreements expire periodically. Although not a common occurrence in Capital Power’s history, the renegotiation of the collective agreements bears the risk of labour disruption or significant increases in labour costs.

The Company’s collective agreement with UNIFOR 829, which represents power engineers at the Genesee power plant, was ratified during 2019 and expires on December 19, 2020. The Company’s collective agreement with IBEW 1007, which represents all employees directly engaged in the maintenance of the electrical generation at Genesee, was also ratified during 2019 and expires on December 19, 2020.

The Company’s collective agreement with CSU 52, which represents certain administrative, technical, professional, and information technology employees located in the Edmonton corporate office and the Genesee power plant, expired on December 23, 2018. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until the new collective agreement is ratified. Negotiations related to the new collective agreement are currently underway.

Strategies employed for managing human resources risk:

- Maintain good human resource programs and practices including appropriate ethics and employee conduct policies and programs, a diversity and inclusion committee, employee engagement tracking, monitoring of developments and contingency planning.
- Maintain competitive compensation programs.
- Maintain succession plans for key positions.
- Maintain good collective bargaining capability, programs and practices.

The development, construction, ownership and operation of Capital Power's generation assets carry an inherent risk of liability related to public health, and worker health and safety due to exposure to high voltage electricity, high pressure steam, moving and rotating machinery, heavy equipment, driving, and environmental hazards.

Strategies employed for managing health and safety risk:

- Maintain an organization-wide health and safety culture and system with regular measurements and compliance audits.
- Maintain facility specific safety programs and work procedures.
- Ensure that contractors and other stakeholders align with Capital Power’s health and safety policies and procedures.

Capital Power strives to right size the resources required to operate and grow in its markets and minimize the cost of those resources. Failure to do so could negatively impact culture, growth and earnings and place the Company at a competitive disadvantage.

Strategies employed for managing cost optimization and efficiency risk:

- Set performance targets and measure and report results compared with those targets. Measure performance against benchmarks.
- Develop and undertake efficiency initiatives and programs.
- Support internal resources by utilizing retention programs and assessing employee engagement with appropriate communication and follow-up.

Finance risk

Capital Power's ability to fund current and future capital requirements, along with its working capital needs is dependent upon access to financial markets. Uncertainty and volatility in the Canadian and U.S. financial markets may adversely affect Capital Power's ability to access and arrange financing under favourable terms and conditions. The cost of capital will also depend upon prevailing market conditions and the business performance of Capital Power as indicated by the assigned corporate credit ratings (see Liquidity and Capital Resources). If Capital Power is unable to access sufficient amounts of capital on acceptable terms, there could be an adverse effect on its business plan and financial condition.

Strategies employed for managing credit rating risk:

- Maintain strong relationships with credit rating agencies.
- Develop flexible financial structuring to adapt if circumstances would cause a credit rating downgrade from investment grade.

When Capital Power uses financial instruments to sell power forward, it may be required to post significant amounts of cash collateral or other credit support to its counterparties.

Strategies employed for managing liquidity risk:

- Monitor cash and currency requirements on a regular basis by preparing short-term and long-term cash flow forecasts and by matching the maturity profiles of financial assets and liabilities to identify financing requirements.
- Maintain strong relationships with banks, investment banks and other financial counterparties.

- Meet financing requirements through a combination of committed and demand revolving credit facilities, financings in public and private capital debt markets, and equity offerings.

Counterparty risk is the possible financial loss associated with the potential inability of counterparties to satisfy their contractual obligations to Capital Power, including payment and performance. In the event of default by a purchasing counterparty, existing PPAs and other agreements may not be replaceable on similar terms. Capital Power is also dependent upon its cogeneration hosts and suppliers of fuel to its plants. If a wholesale electricity market counterparty defaults, Capital Power may not be able to replace such counterparty to effectively manage short or long energy positions, resulting in reduced revenues or increased power costs. Furthermore, a prolonged deterioration in economic conditions could increase the foregoing risks.

The Company is party to a contract whereby it sells RECs to Pacific Gas and Electric Company (PG&E) which, in January 2019, filed for bankruptcy and subsequently had its credit rating downgraded to "D", representing default. PG&E faces political and regulatory pressure and needs the support of multiple stakeholders before they will be able to exit from bankruptcy. At this time, PG&E has continued to fulfill their obligations to the Company under the contract. As PG&E's bankruptcy proceeds, the Company will continue to monitor the situation. If at some point, PG&E is no longer able to fulfill their obligations under the contract, the Company would have to pursue replacement contracts which may not be replaceable on similar terms to the existing contract.

Strategies employed for managing counterparty credit risk:

- Maintain a credit policy including limits for credit risk exposure levels.
- Conduct periodic credit reviews on existing counterparties.
- Use credit enhancements such as cash deposits, prepayments, parent company guarantees, bank letters of credit, master netting agreements, margin accounts and credit derivatives.
- Monitor and report credit risk exposures.

Extreme natural and other unexpected events risk

Capital Power's operations are exposed to potential damage resulting from extreme storm and other weather conditions and natural disasters. In addition, major accidents or events including environmental incidents and physical terrorist attacks are possible and the negative consequences could be significant.

Strategies employed for managing extreme events risk:

- Establish and maintain emergency and other related contingency planning measures to enable the timely response to and recovery from extreme weather and other events.
- Maintain appropriate insurance coverage.
- Regular communication with external governmental and industry groups to share threat intelligence, trend analysis, and best practices.
- Establish and maintain a physical security management program that is based on industry guidelines and best practices.
- Periodic internal audits of our facilities to ensure that physical security measures are aligned with the Company's risk profile.

Competition, acquisition, development and construction risk

In the course of assessing development and acquisition opportunities, Capital Power may be required to incur significant expenditures, such as those related to preliminary engineering, permitting, legal and other expenses, before determining whether a project is feasible and economically viable. There can be no assurance that Capital Power will pursue or win any opportunity assessed.

The risks associated with acquisitions of additional companies or assets in the power generation industry include the failure to identify material problems during due diligence, the overpayment for assets and the inability to arrange financing for an acquisition. Further, the integration and consolidation of acquisitions requires substantial human, financial and other resources. There can be no assurances that any future acquisitions will perform as expected or that the returns from such acquisitions will cover the cost of financing incurred to acquire them or the capital expenditures needed to develop them.

In developing and constructing a power generation facility, there are numerous tasks Capital Power must complete. These include obtaining government permits and approvals, site agreements, construction contracts, access to power grids, electrical transmission agreements, fuel supply and transportation agreements, equipment, and financing. There can be no assurance that Capital Power will be successful in completing such tasks on a timely basis or at all. The development and future operation of power generation facilities can be adversely affected by changes in government policy and regulation, environmental concerns, stakeholder activism, increases in capital costs, increases in interest rates, competition in the industry, labour and parts availability, labour disputes, increases in material costs and other matters beyond the control of Capital Power. In the event that a project is not completed or does not operate at anticipated performance levels, Capital Power may not be able to recover its investment.

Strategies employed for managing competition, acquisition, development, and construction risk:

- Perform detailed project analyses, risk assessments and due diligence prior to and during construction or acquisition.
- Perform post-implementation evaluation of all major acquisition and development projects to improve internal capabilities and processes and to leverage lessons learned for future projects. When necessary, corrective actions are taken to increase the likelihood of investment recovery.
- Enter into favourable long-term contracts for the projects' output, whenever possible.
- Establish positive relationships with suppliers.

Ongoing research and development activities improve upon existing power technologies and reduce the cost of alternative methods of power generation. As identified by ongoing research and development activities, Capital Power's facilities may over time be unable to compete with newer more efficient facilities utilizing improvements to existing power technologies and cost-efficient new technologies.

Tax risk

Capital Power's operations are complex and the determination of income taxes involves income tax interpretations, regulations and legislation that are continually changing. It is not possible to predict, with complete accuracy, changes in the legislative environment or their impact on the Company's income tax status. Future changes in tax legislation may have an adverse impact on Capital Power, its shareholders and the value of the Company's common shares.

Capital Power's tax filings are subject to audit by taxation authorities. While Capital Power maintains that its tax filings have been made in accordance with all such tax interpretations, regulations, and legislation, Capital Power cannot guarantee that it will not have disagreements with taxation authorities with respect to its tax filings.

The statutory income tax rates on income before tax were 26.5% and 27% for 2019 and 2018, respectively. The effective income tax rate can change depending on the mix of earnings from various jurisdictions, and on deductions and inclusions in determining taxable income that do not fluctuate with earnings.

Strategies employed for managing tax risk:

- Develop and maintain tax expertise and resources necessary to interpret tax legislation.
- Consult with all levels of government with respect to tax policy development and proposed legislation.
- Develop and maintain tax expertise and resources necessary, including third party advisors, to understand tax legislation.
- Comply with tax laws of jurisdictions that Capital Power operates in.

Foreign exchange risk

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar affect Capital Power's capital and operating costs, revenues and cash flows and could have an adverse impact on Capital Power's financial performance and condition. The U.S. facility operations and the foreign-sourced equipment required for capital projects are transacted in U.S. dollars. In addition, certain indebtedness is denominated in U.S. dollars.

Strategies employed for managing foreign exchange risk:

- Utilize foreign currency forward contracts.
- Utilize cross-currency interest rate swap contracts.
- Contract significant purchases or borrowings in Canadian dollars.
- Utilize U.S. dollar denominated borrowings and/or tax equity debt financing to finance U.S. developments.

Performance of assets of joint arrangements risk

Some of Capital Power's assets are operated through joint arrangements under which Capital Power is not the operator of the associated assets. There is a risk that the assets will not be operated in accordance with Capital Power's expectations or requirements which could result in financial loss to the Company. While contractual agreements help minimize risk, there can be no assurance that such operations will continue to be effective.

The occurrence of an event which disrupts the ability of facilities operated by external parties to produce or sell power or thermal energy for an extended period would likely require Capital Power to replace the electricity at market prices prevailing at that time. Depending on market liquidity, these market prices could be significantly higher than the prices inherent in the joint arrangements, thus increasing the cost of energy purchases to Capital Power.

Strategies employed for joint arrangements risk:

- Work with facility owner and/or operator to execute appropriate operating and maintenance practices to minimize the likelihood of prolonged unplanned down time.
- Measure performance against benchmarks.
- Establish positive relationships with all parties to the joint arrangements.
- Actively participate in management committees of joint operations.

- Proactively manage the contract's rights and obligations based on thorough understanding of the contract.
- Proactively assess and resolve any contract issues including force majeure claims and appropriately respond with dialogue, advocacy, negotiation, arbitration and legal actions, as required.

General economic conditions, business environment and other risks

In addition to all the risks previously described, the Company is subject to adverse changes in its markets and general economic conditions as well as technology and business model disruption. The Company is exposed to risks associated with weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

Evolving technologies in the industry may impact the success of the Company's strategy (see Corporate Strategy). Management evaluates the Company's strategy on an ongoing basis and monitors technology changes in the industry. The Company's focus on sustainability is a key component in ensuring that the Company's business model remains flexible and resilient as technology evolves.

The Company is dependent upon cash dividends, distributions or other transfers from its subsidiaries, including CPLP, in order to repay any debt the Company may incur, to make dividend payments to its shareholders and to meet its other obligations. The right of the Company, as a unitholder or shareholder of these entities, to realize on the assets of these entities in the event of their bankruptcy or insolvency, would be subordinate to the rights of their creditors and claimants preferred by statute. The terms of the credit facilities of the Company's subsidiaries prohibit them from making distributions if an event of default has occurred and is continuing or would reasonably be expected to result from the distribution. As of December 31, 2019, the Company loaned $2,704 million to the respective subsidiaries under subordinated debt agreements. The terms of these agreements allow interest to be deferred. If interest is deferred, then CPLP has covenanted not to make distributions on any of its outstanding common limited partnership units.

Weather can have a significant impact on Capital Power's operations. Temperature levels, seasonality and precipitation, both within Capital Power's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility.

In the normal course of Capital Power's operations, the Company may become involved in various legal proceedings including arbitration of the interpretation of any contract. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty. However, the Company does not believe that the outcome of any claims or potential claims of which it is aware, which have not already been provided for, will have a material adverse effect on Capital Power's financial condition and results of operations (see Contractual Obligations, Contingent Liabilities, Other Legal Matters and Provisions).

The Company considers reputation risk to be a consequence of all other risks that it faces. If a certain risk factor results in positive or negative consequences to the Company, its reputation may also be positively or negatively affected. In part, the Company manages its reputation risk by employing appropriate risk management strategies for all identified risks.

Capital Power's property, boiler and machinery, business interruption and liability insurance coverages are established and maintained to minimize financial exposures associated with extreme weather and other events. The insurance coverages are subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. There can be no assurance that such insurance will continue to be offered on an economically feasible basis or that all events that could give rise to a loss or liability are insurable.

The various risks noted within this Risks and Risk Management section may be compounded by the level of exposure to a given geographic area, regulatory environment or technology. The Company continues to mitigate these risks through its development and acquisition activities. These activities have allowed the Company to reduce its proportionate exposure to Alberta, while expanding its footprint in Ontario and the U.S. These activities have also resulted in an increase to the Company's proportionate investment in renewables and natural gas assets compared to coal assets as well as an increase in contracted cash flows. Diversifying the Company's portfolio can result in the Company entering new markets which can bring new uncertainties which the Company mitigates as described above under strategies employed for managing competition, acquisition, development and construction risk.

There can be no assurance that any risk management steps taken by Capital Power with the objective of mitigating the foregoing risks will avoid future loss due to the occurrence of such risks.

ENVIRONMENTAL MATTERS

The Company recorded decommissioning provisions of $356 million as at December 31, 2019 ($259 million as at December 31, 2018) for its generation facilities and the Genesee Coal Mine as it is obliged to remove the facilities at the end of their useful lives and restore the facility and mine sites to their original condition. Decommissioning provisions for the Genesee Coal Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. The timing of reclamation activities could vary and the amount of decommissioning provisions could change depending on potential future changes in environmental regulations and the timing of any facility fuel conversions.

The Company has forward contracts to purchase environmental credits totaling $467 million and forward contracts to sell environmental credits totaling $435 million in future years. Included within these forward purchases and sales are net purchase amounts which will be used by the Company to comply with applicable environmental regulations and net sales amounts related to other emissions trading activities.

REGULATORY MATTERS

Alberta

On April 16, 2019, the Province of Alberta held an election resulting in the United Conservative Party forming a majority government that replaced the previous New Democratic Party. On July 24, 2019, the Government of Alberta announced its decision to cancel plans to transition the province's electricity market structure to a capacity market from an energy-only market. Capital Power remains well positioned to compete in an energy-only market through our market and commodity management expertise, young, diverse and efficient fleet of assets, and pipeline of development projects.

In July of 2019, the Government of Alberta also announced that the province's existing carbon policy, the Carbon Competitiveness Incentive Regulation (CCIR), would be replaced by a new regime, the Technology Innovation and Emissions Reduction (TIER) program effective January 1, 2020. The TIER program and its impact on electricity producers is expected to be largely comparable to CCIR. In 2019, the federal Greenhouse Gas Pollution Pricing Act (GGPPA) Regulations were amended to implement charges on fossil fuels for Alberta beginning January 1, 2020 in response to the absence of an Alberta economy wide carbon levy. The governments of Alberta, Saskatchewan, Manitoba and Ontario have put forward constitutional challenges of the GGPPA. Alberta's TIER regime, including as it applies to large power generation, has been deemed compliant with federal standards for 2020.

In 2016, the Canadian federal government announced the Pan-Canadian Framework (PCF) on Clean Growth and Climate Change. The key elements of the PCF are carbon pricing as implemented by the provinces and territories, coal phase-out by December 31, 2029, and the opportunity to extend the life of coal units through conversion to natural gas. The Canadian federal government's Output-Based Pricing System came into effect in January 2019 and applies to provinces and territories without their own equivalent program (currently Ontario, Manitoba, New Brunswick, Prince Edward Island, and select sectors in Saskatchewan). In December 2019, Alberta's TIER framework was deemed equivalent for 2020. Changes to the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation were also finalized in 2018 and set the GHG emission requirements for coal units converted to natural gas (CTG) units. These regulations impacted the useful lives of the Company's current coal assets, commencing in 2019, as described within Use of Judgments and Estimates.

Ontario

Ontario's IESO unexpectedly announced in July 2019 that it was cancelling further work on a broad capacity market framework. In reviewing its long-term planning outlook, the IESO advised that it expects sufficient capacity to exist in the market for the next ten-year period particularly if resources are re-acquired when their existing contracts expire. The process to recontract assets, including those owned by the Company, is expected to commence in 2020 and is likely to include a combination of bilateral contract extensions and competitive processes.

Concurrently, the Ontario government issued a directive on November 6, 2019, requiring the IESO to retain a third party and undertake a targeted review of existing large gas and wind generation contracts to identify opportunities to lower overall electricity costs. A report on key findings and recommendations resulting from the review is due by February 28, 2020. As part of this process, the IESO will also seek the perspectives of contract counterparties such as Capital Power on potential cost-savings opportunities. As at this time, it is unknown how the results of the targeted review will affect the Company.

On October 31, 2018, the Government of Ontario passed Bill 4, the *Cap and Trade Cancellation Act, 2018*. Bill 4 repealed the *Climate Change Mitigation and Low-carbon Economy Act, 2016*, and set out the legal framework for a wind-down of the Cap and Trade program. The Federal GGPPA imposes a carbon pricing system on Ontario and other provinces that do not have an equivalent system in place to meet targeted GHG reduction levels. On July 4, 2019, the Government of Ontario published the final Greenhouse Gas Emissions Performance Standards (Ontario Regulation 241/19) and the regulation also came into effect on the day it was filed. However, the first compliance period is not until the Federal Government removes Ontario from Part 2 of Schedule 1 of the Federal GGPPA. As such, the GGPPA will remain in effect in Ontario until 2022. The PPAs for York Energy, East Windsor and Goreway have a provision that triggers a contractual amendment, the effect of which will enable recovery of any imposed federal carbon compliance costs. Accordingly, the Company does not believe the implementation of a federal carbon pricing system or any potential provincial GHG system will have a material adverse effect on its financial condition and results of operations.

USE OF JUDGMENTS AND ESTIMATES

In preparing the audited consolidated financial statements, management made judgments, estimates and assumptions that affect the application of the Company's accounting policies and the reported amount of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to estimates are recognized prospectively.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's audited consolidated financial statements relate to:

Judgment	Management applies judgment to evaluate	Resulting conclusions
Cash generating units	What constitutes a CGU based on the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.	CGUs were determined giving consideration to geographic proximity and shared risk exposure and risk management.
Asset impairment	Whether events or circumstances may indicate that an asset's carrying amount exceeds its recoverable amount.	No indicators were identified during 2019 that required impairment testing beyond annual testing of the East Windsor CGU which contains goodwill.
Whether an arrangement contains a lease	Whether a PPA or similar contract conveys the right to control the Company's property, plant and equipment in return for payment, and, if so, a lease exists.	Contracts that convey the right to control Capital Power's property, plant and equipment and, therefore, are considered operating leases with the Company as the lessor: • Genesee 1 and 2 PPA • Island Generation PPA • Decatur Energy tolling agreement • Arlington Valley tolling agreement The Company has been determined to be the lessee for the following: • Beaufort Solar sale and leaseback agreement • Various office, equipment and land leases
Control of subsidiaries that are less than wholly-owned	Whether certain subsidiaries are controlled by the Company even though the subsidiaries are less than wholly-owned.	Since the Company has majority rights, the Genesee Coal Mine and Macho Springs facility are consolidated and have non-controlling interests.
Classification of joint arrangements	How joint arrangements structured through a separate vehicle should be classified; either as a joint venture or a joint operation.	York Energy is accounted for as a joint venture because each of the partners effectively has rights to the net assets of the arrangement. Joffre, Shepard and Genesee 4 and 5 are accounted for as joint operations because each of the joint operators has rights to the assets and obligations for the liabilities of the arrangements and rights to the corresponding revenues and obligations for the corresponding expenses.
Operating segments	Whether the Company operates in one or multiple business segments, and if the Company operates in multiple segments, how the aggregation criteria are applied to reportable segments.	The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large industrial and commercial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

Assumptions and estimation uncertainties

The following identifies key information about assumptions and estimation uncertainties that could have a significant risk of resulting in material adjustments:

Estimate	Impacts and assumptions subject to estimation uncertainty
Measurement of fair values	Carrying amounts for financial instruments • Amounts and timing of future cash flows • Future prices • Future interest rate yield curves • Volatility
	Impairment of financial and non-financial assets and liabilities • Discount rates • Growth rates • Other cash flow assumptions including revenues, expenses and capital expenditures • Future generating capacity • Contract renewals and rates adjusted for inflation • Fuel mix at optimized levels
	Decommissioning and other provisions • Discount rates • Amount and timing of asset retirement • Extent of site remediation required • Future cash flows based on amount and timing of settlement of obligation • Expected customer renewals for other provisions
	Share-based payments • Expected volatility, option life and dividend yield • Risk-free interest rate
	Purchase price allocations for financial and non-financial assets and liabilities • Same fair value measurement factors and assumptions as applicable to determine carrying amounts for derivative financial instruments, impairment of financial and non-financial assets and liabilities, and decommissioning and other provisions.
Depreciation and amortization	Assets useful lives are based on the life characteristics of common assets and the expectation of coal asset fuel conversion to allow for generation post-2029. As a result of the Amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, and the changes to Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation, commencing in 2019, Capital Power prospectively adjusted the useful lives of its current coal assets to reflect these new expected end of life dates. This included adjusting the lives of asset components that could be used in a CTG conversion to the new estimated life as set out by the federal government.
Recognition of deferred tax assets and availability of future taxable income against which carry forward tax losses can be used.	Deferred tax assets and income tax provisions are based on the likelihood that tax losses will be recovered from future taxable income.

ACCOUNTING CHANGES

Effective January 1, 2019

The Company adopted one new accounting standard as issued by the International Accounting Standards Board. The standard and impact to Capital Power were:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
Leases (IFRS 16)	The new standard which replaced IAS 17 – Leases addresses the recognition, measurement, presentation and disclosure of leases. IFRS 16 provides a single lessee accounting model requiring lessees to recognize right-of-use assets and lease liabilities for all leases previously classified as operating leases, including but not limited to, office space leases and land leases. There are no changes to lessor accounting under the new standard. However, the criteria for assessing whether a contract contains a lease have changed.	The Company elected not to grandfather lease assessments, as previously assessed under IAS 17 and IFRIC 4 – Determining Whether an Arrangement Contains a Lease. Management reviewed all contracts and existing lease arrangements to determine the impact of the IFRS 16 adoption. For contracts determined to contain leases with the Company as the lessee under IFRS 16, the Company elected to apply the modified retrospective approach where the lessee does not restate comparative figures and the cumulative effect of initial application of the standard is recognized in the opening deficit balance. The Company recognized right-of-use assets for the underlying assets and lease liabilities for future lease payments. Management determined that certain PPAs and energy supply contracts that were previously considered to be finance leases with the Company as the lessor are no longer considered leases under IFRS 16, but rather are now accounted for under IFRS 15 – Revenue from Contracts with Customers. The transition impact for the former finance leases was accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors and treated as a change in accounting policy.	Effective for annual periods beginning on or after January 1, 2019.

The adjustments to the impacted financial statement categories within the consolidated statements of financial position as a result of changes described in the IFRS 16 discussion above are as follows:

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Assets [1]	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653
Liabilities [2]	3,836	(22)	3,814	4,541	(25)	4,516	90	4,606
Equity [2]	$ 3,062	$ (57)	$ 3,005	$ 3,119	$ (66)	$ 3,053	$ (6)	$ 3,047

1 Under IFRS 16, assets related to leases as the lessee represent right-of-use assets and assets related to leases as the lessor represent property, plant and equipment.

2 The opening deficit adjustments above reflect increase to the opening deficit balances, net of deferred tax impacts at a rate of 27% which also impacts the liabilities amounts as reductions to deferred tax liabilities.

The adjustments to the impacted line items within the consolidated statements of income pertaining to the IAS 8 accounting policy change related to the former finance leases where Capital Power was the lessor were:

	Year ended December 31, 2019			Year ended December 31, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	1,690	1,713	23	1,249	1,272	23
Depreciation and amortization	(438)	(473)	(35)	(300)	(335)	(35)
Income tax recovery (expense)	3	6	3	(93)	(90)	3
Net income (loss) impact			(9)			(9)

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at December 31, 2019 and 2018 were as follows:

(unaudited, $ millions)		December 31, 2019		December 31, 2018	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	248	248	182	182
Trade and other receivables [2]	N/A	281	281	386	386
Government grant receivable [3]	Level 2	476	435	511	505
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See Below	234	234	148	148
Fair value through other comprehensive (loss) income					
Derivative financial instruments assets – current and non-current	See Below	-	-	11	11
Financial liabilities:					
Other financial liabilities					
Trade and other payables	N/A	301	301	244	244
Loans and borrowings [3]	Level 2	3,413	3,505	2,647	2,645
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See Below	106	106	186	186
Fair value through other comprehensive (loss) income					
Derivative financial instruments liabilities – current and non-current	See Below	192	192	18	18

1 Fair values for Level 1 financial assets and liabilities are based on unadjusted quoted prices in active markets for identical instruments while fair values for Level 2 financial assets and liabilities are generally based on indirectly observable prices. The determination of fair values for Level 3 financial assets and liabilities is prepared by appropriate subject matter experts and reviewed by the Company's commodity risk group and by management.

2 Excludes current portion of government grant receivable.

3 Includes current portion.

Risk management and hedging activities

The Company is exposed to changes in energy commodity prices, foreign currency exchange rates and interest rates. The Company uses various risk management techniques, including derivative instruments such as forward contracts, fixed-for-floating swaps, and option contracts, to reduce this exposure. These derivative instruments are recorded at fair value on the Consolidated Statements of Financial Position except for non-financial derivatives that are entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements.

Unrealized changes in the fair value of financial and non-financial derivatives that do not qualify for hedge accounting and non-financial derivatives that do not qualify for the expected purchase, sale or usage requirements of the Company are recognized in net income as revenues, energy purchases and fuel, foreign exchange gain or loss or net finance expense. The corresponding unrealized changes in the fair value of the associated economically hedged exposures are not recognized in income. Accordingly, derivative instruments that are recorded at fair value can produce volatility in net income as a result of fluctuating forward commodity prices, foreign exchange rates and interest rates which are not offset by the unrealized fair value changes of the exposure being hedged on an economic basis. As a result, accounting gains or losses relating to changes in fair values of derivative instruments do not necessarily represent the underlying economics of the hedging transaction.

For example, the Company usually has more physical supply of power in Alberta from its generating units than the Company has contracted to physically sell. The Company utilizes financial sales contracts to reduce its exposure to changes in the price of power in Alberta. Economically, the Company benefits from higher Alberta power prices due to the net long position held since the Company's expected physical supply is in excess of the Company's physical and financial sales contracts. However, financial sales contracts that are not hedged for accounting purposes are recorded at fair value at each statement of financial position date and the offsetting anticipated future physical supply or economically hedged item is not. Accordingly, an increase in forward Alberta power prices can result in fair value losses for accounting purposes whereas on an economic basis, these losses are offset by unrecognized gains on the physical supply. The economic gains will be recognized in later periods when the power is produced and sold. The opposite is true for forward price decreases in Alberta power.

The derivative financial instruments assets and liabilities held at December 31, 2019 and 2018 and used for risk management purposes were measured at fair value and consisted of the following:

(unaudited, $ millions)		As at December 31, 2019				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Interest rate non-hedges**	**Total**
Derivative financial instruments assets	Level 2	-	191	-	2	193
	Level 3	-	41	-	-	41
		-	232	-	2	234
Derivative financial instruments liabilities	Level 2	(23)	(192)	(83)	-	(298)
	Level 3	-	-	-	-	-
		(23)	(192)	(83)	-	(298)
Net derivative financial instruments (liabilities) assets		**(23)**	**40**	**(83)**	**2**	**(64)**

(unaudited, $ millions)		As at December 31, 2018				
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Interest rate cash flow hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	11	120	-	12	143
	Level 3	-	16	-	-	16
		11	136	-	12	159
Derivative financial instruments liabilities	Level 2	(11)	(141)	(7)	(1)	(160)
	Level 3	-	(44)	-	-	(44)
		(11)	(185)	(7)	(1)	(204)
Net derivative financial instruments (liabilities) assets		**-**	**(49)**	**(7)**	**11**	**(45)**

Commodity, interest rate and foreign exchange derivatives designated as accounting hedges

Unrealized gains and losses for fair value changes on commodity, interest rate and foreign exchange derivatives that qualify for hedge accounting are recorded in other comprehensive (loss) income and, when realized, are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gains and losses as appropriate. When interest rate derivatives are used to hedge the interest rate on a future debt issuance, realized gains or losses are deferred within accumulated other comprehensive loss and recognized within finance expense over the life of the debt, consistent with the interest expense on the hedged debt.

Commodity, interest rate and foreign exchange derivatives not designated as accounting hedges

The change in fair values of commodity derivatives not designated as hedges is primarily due to changes in forward Alberta power and natural gas prices and their impact on the Alberta portfolio as well as the change in pricing on U.S. trading relating to the swap arrangements on the Company’s U.S. wind generation. Unrealized and realized gains and losses for fair value changes on commodity derivatives that do not qualify for hedge accounting are recorded in net income as revenues or energy purchases and fuel.

Unrealized and realized gains and losses on foreign exchange derivatives and interest rate derivatives that are not designated as hedges for accounting purposes are recorded in net income as foreign exchange gains or losses and net finance expense, respectively.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

As at December 31, 2019, management conducted an evaluation of the design and operation of the Company's disclosure controls and procedures to provide reasonable assurance that:

(i) material information relating to the Company is made known to management by others, particularly during the period in which the Company's annual filings are being prepared, and

(ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The evaluation took into consideration the Company's Disclosure Policy and internal sub-certification process, and the functioning of its Disclosure Committee. In addition, the evaluation covered the Company's processes, systems and capabilities relating to public disclosures and the identification and communication of material information. Based on that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are appropriately designed and effective.

As at December 31, 2019, management conducted an evaluation of the design and operation of internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's internal controls over financial reporting are appropriately designed and effective.

These evaluations were conducted in accordance with the Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission and the requirements of the Canadian Securities Administrators' National Instrument 52-109.

SUMMARY OF QUARTERLY RESULTS

(GWh)	Three months ended							
Electricity generation	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**
Total generation	6,437	6,808	5,500	5,782	5,406	5,213	4,584	5,026
Alberta commercial facilities								
Genesee 3	1,015	492	502	500	372	495	468	479
Keephills 3	N/A	450	433	470	483	494	434	420
Clover Bar Energy Centre 1, 2 and 3	135	348	264	296	264	217	204	175
Joffre	187	150	205	232	212	154	115	128
Shepard Energy Centre	660	782	679	807	769	789	585	795
Halkirk	129	86	107	120	130	85	103	132
Clover Bar Landfill Gas	-	-	-	-	-	-	-	-
	2,126	2,308	2,190	2,425	2,230	2,234	1,909	2,129
Alberta contracted facilities								
Genesee 1	848	803	556	837	877	829	751	811
Genesee 2	826	795	698	848	850	799	647	663
Whitla Wind 1	77	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	1,751	1,598	1,254	1,685	1,727	1,628	1,398	1,474
Ontario and British Columbia contracted facilities								
Island Generation	8	379	166	168	-	17	-	10
York Energy	5	3	4	4	2	3	3	2
East Windsor	4	2	3	2	1	4	2	2
Goreway	157	304	76	N/A	N/A	N/A	N/A	N/A
K2 Wind	N/A	N/A	N/A	N/A	70	35	41	76
Kingsbridge 1	34	15	20	36	33	14	20	36
Port Dover and Nanticoke	84	46	65	99	78	43	70	108
Quality Wind	130	73	77	74	112	74	98	78
EnPower	10	3	5	5	3	10	11	14
	432	825	416	388	299	200	245	326
U.S. contracted facilities								
Roxboro, North Carolina	86	88	88	62	74	87	90	76
Southport, North Carolina	127	112	121	99	106	104	118	111
Decatur Energy, Alabama	656	709	372	408	674	784	576	669
Arlington Valley, Arizona	912	878	750	394	87	N/A	N/A	N/A
Beaufort Solar, North Carolina	6	8	9	6	5	8	8	6
Bloom Wind, Kansas	197	176	169	175	164	152	197	198
Macho Springs, New Mexico	29	21	43	39	31	16	43	37
New Frontier Wind, North Dakota	115	85	88	101	9	N/A	N/A	N/A
	2,128	2,077	1,640	1,284	1,150	1,151	1,032	1,097

(%)	Three months ended							
Facility availability	**Dec 31 2019**	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**
Total average facility availability	94	96	92	96	94	98	93	96
Alberta commercial facilities								
Genesee 3	100	96	100	100	74	98	98	97
Keephills 3	N/A	93	92	99	100	100	100	92
Clover Bar Energy Centre 1, 2 and 3	86	96	91	97	85	88	90	93
Joffre	89	82	100	100	100	97	90	93
Shepard Energy Centre	79	100	86	97	100	100	68	100
Halkirk	99	95	98	98	98	95	98	98
Clover Bar Landfill Gas	-	-	-	-	-	7	78	-
	90	95	93	98	93	96	87	96
Alberta contracted facilities								
Genesee 1	100	96	72	100	100	99	100	100
Genesee 2	100	100	95	100	98	100	93	83
Whitla Wind 1	97	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	100	98	83	100	99	99	97	92
Ontario and British Columbia contracted facilities								
Island Generation	92	99	100	100	100	100	100	100
York Energy	94	99	100	100	100	100	94	100
East Windsor	97	99	99	99	99	99	99	99
Goreway	88	87	99	N/A	N/A	N/A	N/A	N/A
K2 Wind	N/A	N/A	N/A	N/A	99	98	100	98
Kingsbridge 1	99	98	97	98	99	98	98	98
Port Dover and Nanticoke	97	94	100	99	98	94	99	100
Quality Wind	98	96	98	96	95	94	97	97
EnPower	91	72	97	55	97	100	86	97
	91	92	99	98	99	98	98	99
U.S. contracted facilities								
Roxboro, North Carolina	88	99	100	88	97	100	99	88
Southport, North Carolina	96	84	90	91	83	100	95	89
Decatur Energy, Alabama	93	100	81	98	85	100	94	100
Arlington Valley, Arizona	99	100	100	81	94	N/A	N/A	N/A
Beaufort Solar, North Carolina	98	100	100	100	97	100	98	93
Bloom Wind, Kansas	99	98	98	99	100	97	96	98
Macho Springs, New Mexico	98	97	99	98	99	97	98	97
New Frontier Wind, North Dakota	94	97	95	96	98	N/A	N/A	N/A
	96	99	91	92	89	99	95	98

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2019	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**
Revenues and other income								
Alberta commercial facilities and portfolio optimization	214	181	150	180	150	148	116	173
Alberta contracted facilities	73	68	46	74	71	70	66	61
Ontario and British Columbia contracted facilities [3]	102	88	56	47	52	37	41	50
U.S. contracted facilities	103	149	102	95	63	74	102	65
Corporate [1]	141	15	17	15	13	15	15	15
Unrealized changes in fair value of commodity derivatives and emission credits	50	16	(5)	(14)	(9)	51	29	(51)
	683	**517**	**366**	**397**	**340**	**395**	**369**	**313**
Adjusted EBITDA								
Alberta commercial facilities and portfolio optimization	80	72	71	84	62	60	51	55
Alberta contracted facilities	57	49	32	53	53	54	51	45
Ontario and British Columbia contracted facilities [2, 3]	77	63	48	44	52	37	45	59
U.S. contracted facilities	40	115	54	38	25	44	72	35
Corporate	98	(15)	(14)	(17)	(21)	(16)	(12)	(15)
	352	**284**	**191**	**202**	**171**	**179**	**207**	**179**

1 Revenues are offset by interplant category revenue eliminations.

2 The reported Ontario and British Columbia contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture. Prior quarters' values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

Quarterly revenues, net income (loss) and cash flows from operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned facility outages and items outside the normal course of operations. Net income (loss) is also affected by changes in the fair value of the Company's power, natural gas, interest rate and foreign exchange derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018
Revenues and other income [5]	683	517	366	397	340	395	369	313
Adjusted EBITDA [1, 2, 3, 5]	352	284	191	202	171	179	207	179
Net income (loss) [5]	181	(228)	106	60	136	17	66	39
Net income (loss) attributable to shareholders of the Company [5]	182	(226)	108	61	138	18	68	41
Basic earnings (loss) per share ($) [5]	1.61	(2.25)	0.93	0.49	1.24	0.08	0.55	0.30
Diluted earnings (loss) per share ($)[4,5]	1.60	(2.25)	0.92	0.49	1.24	0.08	0.55	0.30
Normalized earnings per share ($) [1, 5]	0.29	0.60	0.14	0.29	0.30	0.33	0.20	0.28
Net cash flows from operating activities	201	209	114	196	133	65	109	143
Adjusted funds from operations [1]	128	225	85	117	80	156	76	85
Adjusted funds from operations per share ($) [1]	1.22	2.11	0.82	1.15	0.78	1.52	0.74	0.82
Purchase of property, plant and equipment and other assets	112	193	279	51	114	135	66	40

1 The consolidated financial highlights, except for adjusted EBITDA, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share were prepared in accordance with GAAP. See Non-GAAP Financial Measures.

2 The reported Ontario and British Columbia contracted facilities' adjusted EBITDA includes the adjusted EBITDA from the York Energy joint venture. Prior quarters' values include Capital Power's share of K2 Wind which was disposed of effective December 31, 2018.

3 Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA excludes unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change was made to better align the Company's measure of adjusted EBITDA with its other non-GAAP measures, as both the adjusted funds from operations and the normalized earnings per share measures exclude the impacts of unrealized changes in fair value of commodity derivatives and emission credits. Comparative figures have been restated to reflect the above change to the adjusted EBITDA metric.

4 Diluted earnings per share was calculated after giving effect to outstanding share purchase options.

5 Prior quarters' amounts have been restated to reflect the IAS 8 accounting policy change resulting from the transition to IFRS 16, see Accounting Changes.

	Three months ended							
Spot price averages	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018
Alberta power ($ per MWh)	47	47	57	69	56	55	56	35
Alberta natural gas (AECO) ($ per Gj)	2.32	0.99	1.17	2.62	1.59	1.15	1.10	1.99
Capital Power's Alberta portfolio average realized power price ($ per MWh)	57	59	55	58	52	54	51	47

Factors impacting results for the fourth quarter of 2019

For the quarter ended December 31, 2019, the Company recorded net income attributable to shareholders of $182 million compared to net income attributable to shareholders $138 million for the quarter ended December 31, 2018. Gains in the fourth quarter of 2019 related to the Genesee 3 and Keephills 3 swap transaction (see Significant Events) were largely offset by the gain on disposal of the Company's minority owned interest in K2 Wind during the fourth quarter of 2018. Increases in net income in the fourth quarter of 2019 were driven partly by unrealized gains on commodity derivatives and emission credits being $81 million higher than in the comparable 2018 period, most notably related to the impact of decreasing forward prices on forward sales contracts for the Company's U.S. wind facilities. In addition, adjusted EBITDA was higher as a result of the 2019 addition of Goreway (see Significant Events) and the acquisition of Arlington Valley and commercial operation of New Frontier Wind in the fourth quarter of 2018 as well as higher Alberta commercial EBITDA on higher captured pricing. Partially offsetting these increases was a corresponding increase in depreciation driven by the noted asset additions. Further offsetting the increases in net income were higher tax expenses in the fourth quarter of 2019 primarily due to recognition of deferred income tax expense on the one-time adjustment to accelerate the recognition of deferred government grant revenue upon close of the Genesee 3 and Keephills 3 swap transaction, partially offset by the reversal of deferred income tax expense on the disposal of Keephills 3.

Factors impacting results for the previous quarters

Significant events and items which affected results for the previous quarters were as follows:

For the quarter ended September 30, 2019, the Company recorded net loss attributable to shareholders of $226 million compared to net income attributable to shareholders of $18 million for the quarter ended September 30, 2018. The decrease was largely due to pre-tax impairment of $401 million on Keephills 3 upon classification as an asset held for sale (see Significant Events). Further contributing to the decrease was higher depreciation and amortization due to New Frontier Wind commencing commercial operation in the last quarter of 2018 and the acquisitions of Arlington Valley and Goreway (see Significant Events) in the last quarter of 2018 and second quarter of 2019, respectively, partly offset by depreciation for Keephills 3 ceasing following its classification as held for sale in August 2019. Higher net loss attributable to shareholders was partially offset by an increase in adjusted EBITDA, most notably due to the addition of Goreway and Arlington Valley and the commencement of operations at New Frontier Wind, as well as an increase in unrealized gains on commodity derivatives and emission credits, which were $43 million higher in the third quarter of 2019 compared to the third quarter of 2018. In addition, income tax recovery for the third quarter of 2019 was $66 million compared to income tax expense of $7 million for the third quarter of 2018, primarily due to the recognition of a deferred tax recovery on the impairment of Keephills 3.

For the quarter ended June 30, 2019, the Company recorded net income attributable to shareholders of $108 million compared to net income attributable to shareholders of $68 million for the quarter ended June 30, 2018. The increase mainly resulted from an income tax recovery of $33 million in the second quarter of 2019 compared to income tax expense of $46 million in the second quarter of 2018 primarily due to a reduction in the Alberta corporate income tax rate enacted in the second quarter of 2019. Further contributing to the increase were unrealized gains on commodity derivatives and emission credits which were $26 million higher in the second quarter of 2019 compared to the second quarter of 2018. These variances were partially offset by higher depreciation and amortization due to New Frontier Wind commencing commercial operation in the last quarter of 2018 and the acquisitions of Arlington Valley and Goreway in the last quarter of 2018 and second quarter of 2019, respectively. In addition, adjusted EBITDA was lower in the second quarter of 2019 compared to the second quarter of 2018, largely due to the timing and length of planned outages and the impact of the Bloom Wind tax equity agreement renegotiation in the second quarter of 2018, offset partially by higher margins earned on the sale of emission credits in the second quarter of 2019.

For the quarter ended March 31, 2019, the Company recorded net income attributable to shareholders of $61 million compared to net income attributable to shareholders of $41 million for the quarter ended March 31, 2018. The increase compared to the prior quarter mainly resulted from an increase in adjusted EBITDA most notably due to the higher Alberta power pricing averaging $69 per MWh in the first quarter of 2019 compared to $35 per MWh in the first quarter of 2018, offset partially by lower adjusted EBITDA from joint ventures due to the disposal of K2 Wind in December 2018. Other notable impacts included higher unrealized gains on commodity derivatives and emission credits in 2019 which were higher by $35 million, largely offset by higher depreciation and amortization due to the acquisition of Arlington Valley and New Frontier Wind commencing commercial operation in the last quarter of 2018, and increased income tax expense primarily due to higher consolidated income before tax.

For the quarter ended December 31, 2018, the Company recorded net income attributable to shareholders of $138 million compared to net loss attributable to shareholders of $11 million for the quarter ended December 31, 2017. The increase compared to the prior quarter mainly resulted from the $159 million gain on disposal of the Company's minority owned interest in K2 Wind. In addition, tax expenses were lower by $26 million in the fourth quarter of 2018 as compared to 2017 driven by U.S. federal tax rate decreases in the fourth quarter of 2017 and the resulting reduction in deferred tax assets. These impacts were partially offset by higher unrealized losses on commodity derivatives and emission credits in 2018 which were higher by $35 million.

For the quarter ended September 30, 2018, the Company recorded net income attributable to shareholders of $18 million compared to net loss attributable to shareholders of $7 million for the quarter ended September 30, 2017. Higher net income reflects the recognition of non-cash impairment losses in the third quarter of 2017 totalling $83 million (pre-tax) related to the Company's Southport, Roxboro and Decatur Energy facilities. The Company did not record an impairment loss in 2018. Favourable net income attributed to shareholders was partially offset by a foreign exchange loss of $2 million in the third quarter of 2018 compared to a foreign exchange gain of $21 million in the third quarter of 2017 reflecting a gain on the revaluation of U.S. dollar denominated debt not hedged for accounting purposes, and income tax expense of $7 million in the third quarter of 2018 compared to income tax recovery of $9 million in the third quarter of 2017. Adjusted EBITDA was higher in the third quarter of 2018 compared to the third quarter of 2017 primarily due to the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets. Losses related to unrealized changes in the fair value of commodity derivatives and emission credits were higher in the third quarter of 2018 compared to the third quarter of 2017 largely as a result of the 2018 impact of increasing forward prices on forward sales contracts relating to U.S. energy derivatives.

For the quarter ended June 30, 2018, the Company recorded net income attributable to shareholders of $68 million compared to $107 million for the quarter ended June 30, 2017. Lower net income reflected the reversal of a previous write-down of deferred tax assets related to the tax benefit associated with the Company's U.S. income tax loss carryforwards as a result of the acquisition of Decatur Energy and the commissioning of Bloom Wind in the second quarter of 2017. Further contributing to the decrease were higher net finance expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. These variances were partially offset by higher adjusted EBITDA in the second quarter of 2018 compared to the second quarter of 2017 primarily due to the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets, a full quarter of results from the assets acquired in the second quarter of 2017, and higher Bloom Wind revenue due to the renegotiation of the commercial terms within the Bloom Wind tax equity agreement. Non-cash after tax net income related to Bloom Wind increased $15 million driven by tax rate differences while the $44 million increase in adjusted EBITDA was related to timing.

For the quarter ended March 31, 2018, the Company recorded net income attributable to shareholders of $41 million compared to $46 million for the quarter ended March 31, 2017. The financial results reflected higher unrealized gains on Alberta energy derivatives in the first quarter of 2017 that resulted from the impact of decreasing forward Alberta power prices on net forward sales contracts, partially offset by the reversal of prior year unrealized net gains on forward sales contracts that settled during the first quarter of 2017. Further contributing to the decrease were higher net finance expenses and depreciation and amortization due to the acquisition of the thermal facilities and Decatur Energy and the receipt of Bloom Wind Project financing in the second quarter of 2017. Adjusted EBITDA was higher in the first quarter of 2018 compared to the first quarter of 2017 primarily due to Bloom Wind commencing operations and acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

The Company's common shares are listed on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

	Three months ended							
	Dec 31 2019	**Sep 30 2019**	**Jun 30 2019**	**Mar 31 2019**	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**
Share price ($/common share)								
High	35.09	31.43	32.25	32.44	29.79	29.45	26.00	25.14
Low	30.13	29.31	29.60	26.22	25.33	25.12	23.42	22.15
Close	34.39	30.68	30.15	31.30	26.59	28.51	25.23	24.24
Volume of shares traded (millions)	21.3	18.2	19.6	18.0	25.5	14.8	11.1	14.0

Outstanding share and partnership unit data

As at February 18, 2020, the Company had 105.446 million common shares, 5 million Cumulative Rate Reset Preference Shares, 6 million Cumulative Rate Reset Preference Shares, 8 million Cumulative Rate Reset Preference Shares, 8 million Cumulative Minimum Rate Reset Preference Shares, 6 million Cumulative Minimum Rate Reset Preference Shares, 6 million Cumulative Minimum Rate Reset Preference Shares, and one special limited voting share outstanding. Assuming full conversion of the outstanding and issuable share purchase options to common shares and ignoring exercise prices, the outstanding and issuable common shares as at February 18, 2020 were 108.557 million. The outstanding special limited voting share is held by EPCOR.

As at February 18, 2020, CPLP had 24.040 million general partnership units outstanding and 89.473 million common limited partnership units outstanding. All of the outstanding general partnership units and the outstanding common limited partnership units are held by the Company.

ADDITIONAL INFORMATION

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR at www.sedar.com.

Consolidated Financial Statements of

CAPITAL POWER CORPORATION

(In millions of Canadian dollars)
Years ended December 31, 2019 and 2018

Management's responsibility for financial reporting

The preparation and presentation of the accompanying consolidated financial statements of Capital Power Corporation (the Company) are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards. The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to February 21, 2020. Financial information presented elsewhere in the Company’s integrated annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company’s external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with International Financial Reporting Standards. The independent auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and integrated annual report and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Brian Vaasjo
President and Chief Executive Officer

Bryan DeNeve
Senior Vice President, Finance and
Chief Financial Officer

February 21, 2020

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2019 and 2018

KPMG LLP
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Edmonton, AB T5J 0H3
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Capital Power Corporation

Opinion

We have audited the consolidated financial statements of Capital Power Corporation (the Entity), which comprise:

- the consolidated statements of financial position as at December 31, 2019 and December 31, 2018
- the consolidated statements of income for the years then ended
- the consolidated statements of other comprehensive income for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter – Comparative Information

We draw attention to Note 2 to the financial statements (“Note 2”), which explains that certain comparative information presented:

- for the year ended December 31, 2018 has been restated.
- as at January 1, 2018 has been derived from the financial statements for the year ended December 31, 2017 which have been restated (not presented herein).

Note 2 explains the reason for the restatement and also explains the adjustments that were applied to restate certain comparative information.

Our opinion is not modified in respect of this matter.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors’ report thereon, included in a document likely to be entitled “2019 Integrated Annual Report”.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management’s Discussion and Analysis filed with the relevant Canadian Securities Commissions and the “2019 Integrated Annual Report” as at the date of this auditors’ report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors’ report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the group Entity to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

The engagement partner on the audit resulting in this auditors' report is Ravine Basahti.

KPMG LLP

Chartered Professional Accountants

Edmonton, Canada

February 21, 2020

CAPITAL POWER CORPORATION

Consolidated Statements of Income
(In millions of Canadian dollars, except per share amounts)

Years ended December 31

	2019	2018 (note 2(c))
Revenues	$ 1,713	$ 1,272
Other income (note 6)	250	145
Energy purchases and fuel (note 7)	(418)	(434)
Gross margin	1,545	983
Other raw materials and operating charges	(140)	(124)
Staff costs and employee benefits expense (note 7)	(167)	(145)
Depreciation and amortization (note 7)	(473)	(335)
Impairment (note 5)	(401)	-
Other administrative expense	(116)	(96)
Foreign exchange (loss) gain	(5)	10
Operating income	243	293
Gains on acquisition and disposal transactions (notes 5 and 33)	24	159
Net finance expense (note 8)	(156)	(123)
Income from joint ventures (note 33)	2	19
Income before tax	113	348
Income tax recovery (expense) (note 9)	6	(90)
Net income	$ 119	$ 258
Attributable to:		
Non-controlling interests (note 32)	$ (6)	$ (7)
Shareholders of the Company	$ 125	$ 265

Earnings per share (attributable to common shareholders of the Company):

	2019	2018
Basic (note 10)	$ 0.73	$ 2.17
Diluted (note 10)	$ 0.72	$ 2.16

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Comprehensive Income
(In millions of Canadian dollars)

Years ended December 31

	2019	2018 (note 2(c))
Net income	$ 119	$ 258
Other comprehensive (loss) income:		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial (losses) gains [1]	(6)	2
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized (losses) gains on derivative instruments [2]	(26)	15
Unrealized gains on derivative instruments – joint ventures (note 33) [3]	-	3
Reclassification of losses on derivative instruments to income for the year [4]	9	14
Reclassification of losses on derivative instruments to income for the year – joint ventures (note 33) [5]	-	2
Net investment in foreign subsidiaries:		
Unrealized (losses) gains [6]	(39)	50
Losses realized in net income on disposal of joint venture (note 33) [7]	-	12
Total items that are or may be reclassified subsequently to net income, net of tax	(56)	96
Total other comprehensive (loss) income, net of tax	(62)	98
Total comprehensive income	$ 57	$ 356
Attributable to:		
Non-controlling interests (note 32)	$ (6)	$ (7)
Shareholders of the Company	$ 63	$ 363

[1] For the year ended December 31, 2019, net of income tax recovery of $1. For the year ended December 31, 2018, net of income tax expense of $1.

[2] For the year ended December 31, 2019, net of income tax recovery of $8. For the year ended December 31, 2018, net of income tax expense of $6.

[3] For the years ended December 31, 2019 and December 31, 2018 net of income tax expense of nil and $1, respectively.

[4] For the years ended December 31, 2019 and December 31, 2018, net of reclassification of income tax recoveries of $3 and $5, respectively.

[5] For the years ended December 31, 2019 and December 31, 2018 net of reclassification of income tax recoveries of nil and $1, respectively.

[6] For the years ended December 31, 2019 and December 31, 2018, net of income tax of nil.

[7] For the year ended December 31, 2018, net of reclassification of income tax recovery of $4.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

As at December 31

	2019	2018 (note 2(c))
Assets		
Current assets:		
Cash and cash equivalents (note 11)	$ 248	$ 182
Trade and other receivables (note 12)	334	438
Inventories (note 13)	203	200
Derivative financial instruments assets (note 14)	83	77
	868	897
Non-current assets:		
Other assets	53	66
Derivative financial instruments assets (note 14)	151	82
Government grant receivable (note 15)	423	459
Deferred tax assets (note 16)	24	59
Equity-accounted investments in joint ventures (note 33)	132	142
Right-of-use assets (note 17)	95	-
Intangible assets (note 18)	760	473
Property, plant and equipment (note 19)	6,089	5,356
Goodwill	35	35
Total assets	$ 8,630	$ 7,569

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Financial Position
(In millions of Canadian dollars)

As at December 31	2019	2018 (note 2(c))
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 20)	$ 301	$ 244
Derivative financial instruments liabilities (note 14)	180	90
Loans and borrowings (note 21)	857	456
Deferred revenue and other liabilities (note 23)	60	62
Provisions (note 24)	41	54
	1,439	906
Non-current liabilities:		
Derivative financial instruments liabilities (note 14)	118	114
Loans and borrowings (note 21)	2,556	2,191
Lease liabilities (note 17)	105	17
Deferred revenue and other liabilities (note 23)	383	587
Deferred tax liabilities (note 16)	512	410
Provisions (note 24)	416	291
	4,090	3,610
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 25)	3,441	3,200
Deficit	(347)	(222)
Other reserves	(30)	32
Deficit and other reserves	(377)	(190)
	3,064	3,010
Non-controlling interests (note 32)	37	43
Total equity	3,101	3,053
Total liabilities and equity	$ 8,630	$ 7,569

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Donald Lowry
Director and Chair of the Board

Katharine Stevenson
Director and Chair of the Audit Committee

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 25)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit	Equity attributable to shareholders of the Company	Non-controlling interests (note 32)	Total
Equity as at January 1, 2019 (note 2(c))	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (222)	$ 3,010	$ 43	$ 3,053
Accounting policy changes:									
Impact of IFRS 16 (note 2(c))	-	-	-	-	-	(8)	(8)	-	(8)
Tax impact of IFRS 16 (note 2(c))	-	-	-	-	-	2	2	-	2
Adjusted equity as at January 1, 2019	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (228)	$ 3,004	$ 43	$ 3,047
Net income	-	-	-	-	-	125	125	(6)	119
Other comprehensive income (loss):									
Defined benefit plan actuarial loss	-	-	-	(7)	-	-	(7)	-	(7)
Cash flow derivative hedge losses	-	(34)	-	-	-	-	(34)	-	(34)
Reclassification of losses to net income	-	12	-	-	-	-	12	-	12
Unrealized loss on foreign currency translation	-	-	(39)	-	-	-	(39)	-	(39)
Tax on items recognized directly in equity	-	5	-	1	-	-	6	-	6
Other comprehensive (loss) income	$ -	$ (17)	$ (39)	$ (6)	$ -	$ -	$ (62)	$ -	$ (62)
Total comprehensive (loss) income	-	(17)	(39)	(6)	-	125	63	(6)	57
Common share dividends (note 25)	-	-	-	-	-	(195)	(195)	-	(195)
Preferred share dividends (note 25)	-	-	-	-	-	(48)	(48)	-	(48)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Issue of share capital	300	-	-	-	-	-	300	-	300
Share issue costs	(12)	-	-	-	-	-	(12)	-	(12)
Deferred tax on share issue costs	2	-	-	-	-	-	2	-	2
Common shares purchased	(74)	-	-	-	-	-	(74)	-	(74)
Share-based payments	-	-	-	-	2	-	2	-	2
Share options exercised	25	-	-	-	(2)	-	23	-	23
Equity as at December 31, 2019	$ 3,441	$ (10)	$ (16)	$ (15)	$ 11	$ (347)	$ 3,064	$ 37	$ 3,101

[1] Accumulated other comprehensive loss. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive loss and the employee benefits reserve.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 25)	Cash flow hedges[1]	Cumulative translation reserve[1]	Defined benefit plan actuarial losses[1]	Employee benefits reserve	Deficit (note 2(c))	Equity attributable to shareholders of the Company	Non-controlling interests (note 32)	Total
Equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (181)	$ 3,014	$ 48	$ 3,062
Accounting policy changes:									
Impact of IAS 8 (note 2(c))	-	-	-	-	-	(79)	(79)	-	(79)
Impact of IFRS 15	-	-	-	-	-	(44)	(44)	-	(44)
Tax impact of IAS 8 (note 2(c))	-	-	-	-	-	22	22	-	22
Tax impact of IFRS 15	-	-	-	-	-	11	11	-	11
Adjusted equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (271)	$ 2,924	$ 48	$ 2,972
Net income	-	-	-	-	-	265	265	(7)	258
Other comprehensive income (loss):									
Defined benefit plan actuarial gain	-	-	-	3	-	-	3	-	3
Cash flow derivative hedge gains	-	21	-	-	-	-	21	-	21
Cash flow derivative hedge gains – joint ventures	-	4	-	-	-	-	4	-	4
Reclassification of losses to net income	-	19	-	-	-	-	19	-	19
Reclassification of losses to net income – joint ventures	-	3	-	-	-	-	3	-	3
Unrealized gain on foreign currency translation	-	-	50	-	-	-	50	-	50
Losses realized in net income on disposal of joint venture (note 33)	-	16	-	-	-	-	16	-	16
Tax on items recognized directly in equity	-	(17)	-	(1)	-	-	(18)	-	(18)
Other comprehensive income	$ -	$ 46	$ 50	$ 2	$ -	$ -	$ 98	$ -	$ 98
Total comprehensive income	-	46	50	2	-	265	363	(7)	356
Investment in non-controlling interests (note 32)	-	-	-	-	-	-	-	2	2
Tax on change in non-controlling interests ownership	-	-	-	-	-	4	4	-	4
Common share dividends (note 25)	-	-	-	-	-	(178)	(178)	-	(178)
Preferred share dividends (note 25)	-	-	-	-	-	(41)	(41)	-	(41)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Common shares purchased	(76)	-	-	-	-	-	(76)	-	(76)
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	14	-	-	-	-	-	14	-	14
Equity as at December 31, 2018	$ 3,200	$ 7	$ 23	$ (9)	$ 11	$ (222)	$ 3,010	$ 43	$ 3,053

[1] Accumulated other comprehensive income. Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income and the employee benefits reserve.

See accompanying notes to the consolidated financial statements

CAPITAL POWER CORPORATION

Consolidated Statements of Cash Flows
(In millions of Canadian dollars)

Years ended December 31

	2019	2018 (note 2(c))
Cash flows from operating activities:		
Net income	$ 119	$ 258
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Gains on acquisition and disposal transactions (notes 5 and 33)	(24)	(159)
Impairment (note 5)	401	-
Depreciation and amortization (note 7)	473	335
Net finance expense (note 8)	156	123
Fair value changes on commodity derivative instruments and emission credits held for trading	(118)	67
Foreign exchange losses (gains)	5	(10)
Income tax (recovery) expense (note 9)	(6)	90
Income from joint ventures (note 33)	(2)	(19)
Recognition of government grant deferred revenue	(181)	(51)
Tax equity attributes (note 6)	(57)	(80)
Other items	21	6
Change in fair value of derivative instruments reflected as cash settlement	29	21
Distributions received from joint ventures (note 33)	12	30
Interest paid	(110)	(96)
Other cash items (note 26)	(67)	(22)
Change in non-cash operating working capital (note 26)	69	(43)
Net cash flows from operating activities	720	450
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(635)	(355)
Business acquisitions, net of acquired cash (notes 4 and 5)	(392)	(399)
Proceeds on disposal of joint venture (note 33)	90	126
Government grant received	50	50
Other cash flows from investing activities	19	-
Change in non-cash investing working capital	2	24
Net cash flows used in investing activities	(866)	(554)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	900	705
Repayment of loans and borrowings	(633)	(195)
Issue costs on loans and borrowings	(7)	(6)
Issue of shares (note 25)	300	-
Share issue costs (note 25)	(12)	-
Proceeds from exercise of share options	23	14
Common shares purchased (note 25)	(74)	(76)
Dividends paid (note 25)	(238)	(217)
Realized gains on settlement of foreign exchange derivatives	-	33
Capitalized interest paid	(13)	(5)
Income taxes paid on preferred share dividends	(19)	(19)
Other cash flows used in financing activities	(9)	(1)
Net cash flows from financing activities	218	233
Foreign exchange (loss) gain on cash held in a foreign currency	(6)	1
Net increase in cash and cash equivalents	66	130
Cash and cash equivalents, beginning of year	182	52
Cash and cash equivalents, end of year	$ 248	$ 182

See accompanying notes to the consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) develops, acquires, owns, and operates power generation facilities and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10423 101 Street, Edmonton, Alberta, Canada, T5H 0E9. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol "CPX".

2. Significant accounting policies:

(a) Basis of presentation:

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS).

These consolidated financial statements have been prepared under the historical cost basis, except for the Company's derivative instruments, emission credits held for trading, defined benefit pension plan assets and cash-settled share-based payments, which are stated at fair value.

These consolidated financial statements were approved and authorized for issue by the Board of Directors on February 21, 2020.

(b) Basis of consolidation:

These consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has a 100% interest in each of Capital Power L.P. (CPLP), Capital Power L.P. Holdings Inc., and Capital Power (US Holdings) Inc. (2018 – 100%), which are all controlled by Capital Power and therefore treated as subsidiaries of the Company.

Non-controlling interests in subsidiaries are identified separately from equity attributable to shareholders of the Company. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests' proportionate share of the fair value of the acquired business' identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest's share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

All significant intercompany balances and transactions have been eliminated on consolidation.

(c) Current accounting changes:

Effective January 1, 2019 (date of initial application), the Company adopted IFRS 16 – Leases. The objective of this standard is to provide a foundation for users of financial statements to evaluate the amount, timing and uncertainty of cash flows arising from leases. To meet this objective, the new standard introduces a single lessee accounting model requiring lessees to recognize right-of-use assets and lease liabilities for all leases previously classified as operating leases. There are no changes to lessor accounting under the new standard, however the criteria for assessing whether a contract contains a lease have changed. These assessments now focus on whether the customer controls the use of the identified asset throughout the period of use. As such, certain electricity and natural gas supply contracts where the Company was the lessor are no longer considered a lease under IFRS 16 and the energy revenue is now accounted for under IFRS 15 – Revenue from Contracts with Customers.

The Company has elected not to grandfather lease assessments, as previously assessed under IAS 17 - Leases and IFRIC 4 – Determining Whether an Arrangement Contains a Lease. Management reviewed all contracts and existing lease arrangements in determining the impact of adopting this standard.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

Impact on transition to IFRS 16 - Leases as the lessee

The Company is the lessee in various office, equipment and land leases that were previously accounted for as operating leases. The Company has elected to apply the modified retrospective approach where the lessee will not restate comparative figures and the cumulative effect of initial application of the standard will be recognized in the opening deficit balance at January 1, 2019.

The Company is also the lessee in a sale-and-leaseback transaction for the Beaufort Solar facility. The lease was accounted for as a finance lease under IAS 17 and remains unchanged under the new standard. The carrying amounts of the right-of-use asset and lease liability at January 1, 2019 were determined based on the carrying amounts of the lease asset and liability under IAS 17 immediately before that date.

On initial application, the Company recognized a lease liability of $96 million for future lease payments and a right-of-use asset of $86 million for the underlying assets with the difference recognized in the opening deficit balance. IFRS 16 transition impacts are presented in the tables below.

Measurement:

- Right-of-use assets are measured retrospectively, as if this standard had been applied since the commencement date of each lease, discounted using the Company's incremental borrowing rate at the date of initial application.
- Lease liabilities are measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate at January 1, 2019. The weighted-average incremental borrowing rate was 5.72%.

Practical expedients applied:

- The Company grouped leases with reasonably similar characteristics into portfolios and applied appropriate discount rates to each of these portfolios of leases.
- The Company relied on its assessment of whether leases are onerous by applying IAS 37 – Provisions, Contingent Liabilities and Contingent Assets immediately before the date of initial application as an alternative to performing an impairment review. No leases were determined to be onerous.
- Management excluded initial direct costs from the measurement of the right-of-use assets at the date of initial application.

The following table reconciles the Company's operating lease obligations at December 31, 2018, as previously disclosed in the Company's consolidated financial statements, to the lease liabilities recognized on initial application of IFRS 16 at January 1, 2019.

Operating lease commitments at December 31, 2018	$	142
Discounted using the incremental borrowing rate at January 1, 2019		(65)
Add: Equipment lease contracts		19
Add: Finance lease obligation as at December 31, 2018 [1]		18
Lease liabilities recognized at January 1, 2019 [1]	$	114

[1] At December 31, 2018, $1 million of current finance lease obligations were reclassified from trade and other payables to deferred revenue and other liabilities to conform to the current period's presentation.

Impact on transition to IFRS 16 - Leases as the lessor

Finance leases:

Management has determined that power purchase arrangements (PPAs) and energy supply contracts for Kingsbridge 1, Port Dover and Nanticoke and Quality Wind that were previously considered finance leases with the Company as the lessor are no longer considered leases upon adoption of this standard, but rather will be accounted for under IFRS 15 – Revenue from Contracts with Customers. The transition impact for the former finance leases will be treated as a change in accounting policy and accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

Impact on transition to IFRS 16 - Leases as the lessor, continued

Operating leases*:*

The Company is the lessor in various PPAs where it operates the facilities under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. As such, the Genesee units 1 and 2, Island Generation, Decatur Energy and Arlington Valley power generation facilities continue to be accounted for as assets under operating leases as this classification remains unchanged under the new standard. Management determined that the East Windsor, EnPower and Roxboro PPAs no longer contain a lease under IFRS 16 and the energy revenues will be accounted for under IFRS 15. This change has no impact on the Company's financial statement balances, but will result in additional revenues from contracts with customers.

For further disclosure on the Company's leases, see note 17.

Summarized impacts of IFRS 16 adoption and resulting IAS 8 accounting policy change

The impacts of adopting IFRS 16 on the consolidated statements of financial position as at January 1, 2019 and 2018, inclusive of the related IAS 8 accounting policy changes, were:

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Assets								
Current assets:								
Cash and cash equivalents	$ 52	$ -	$ 52	$ 182	$ -	$ 182	$ -	$ 182
Trade and other receivables	278	(23)	255	462	(24)	438	(2)	436
Inventories	120	-	120	200	-	200	-	200
Derivative financial instruments assets	92	-	92	77	-	77	-	77
	542	(23)	519	921	(24)	897	(2)	895
Non-current assets:								
Other assets	68	-	68	66	-	66	-	66
Derivative financial instruments assets	79	-	79	82	-	82	-	82
Finance lease receivables	644	(644)	-	620	(620)	-	-	-
Government grant receivable	493	-	493	459	-	459	-	459
Deferred tax assets	74	-	74	59	-	59	-	59
Equity-accounted investments in joint ventures	184	-	184	142	-	142	-	142
Right-of-use assets	-	-	-	-	-	-	86	86
Intangible assets	401	-	401	473	-	473	-	473
Property, plant and equipment	4,378	588	4,966	4,803	553	5,356	-	5,356
Goodwill	35	-	35	35	-	35	-	35
Total assets	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

Summarized impacts of IFRS 16 adoption and resulting IAS 8 accounting policy change, continued

	Previously stated at January 1, 2018	IAS 8	Restated as at January 1, 2018	Previously stated at December 31, 2018	IAS 8	Restated as at December 31, 2018	IFRS 16	As at January 1, 2019
Liabilities and equity								
Current liabilities:								
Trade and other payables [2]	$ 216	$ -	$ 216	$ 245	$ (1)	$ 244	$ -	$ 244
Derivative financial instruments liabilities	86	-	86	90	-	90	-	90
Loans and borrowings	239	-	239	456	-	456	-	456
Deferred revenue and other liabilities [2]	58	-	58	61	1	62	5	67
Provisions	37	-	37	54	-	54	-	54
	636	-	636	906	-	906	5	911
Non-current liabilities:								
Derivative financial instruments liabilities	56	-	56	114	-	114	-	114
Loans and borrowings	1,907	-	1,907	2,191	-	2,191	-	2,191
Finance lease obligations [2]	17	-	17	17	(17)	-	-	-
Lease liabilities [2]	-	-	-	-	17	17	91	108
Deferred revenue and other liabilities	581	-	581	587	-	587	(4)	583
Deferred tax liabilities	374	(22)	352	435	(25)	410	(2)	408
Provisions	265	-	265	291	-	291	-	291
	3,200	(22)	3,178	3,635	(25)	3,610	85	3,695
Equity:								
Share capital	3,262	-	3,262	3,200	-	3,200	-	3,200
Deficit [2]	(181)	(57)	(238)	(156)	(66)	(222)	(6)	(228)
Other reserves	(67)	-	(67)	32	-	32	-	32
Deficit and other reserves	(248)	(57)	(305)	(124)	(66)	(190)	(6)	(196)
	3,014	(57)	2,957	3,076	(66)	3,010	(6)	3,004
Non-controlling interests	48	-	48	43	-	43	-	43
Total equity	3,062	(57)	3,005	3,119	(66)	3,053	(6)	3,047
Total liabilities and equity	$ 6,898	$ (79)	$ 6,819	$ 7,660	$ (91)	$ 7,569	$ 84	$ 7,653

[2] Comparative figures have been reclassified to conform to the current year's presentation.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

IAS 8 accounting policy change – impacts on consolidated statements of income

The adjustments to the impacted line items within the consolidated statements of income pertaining to the IAS 8 accounting policy change related to the former finance leases where the Company was the lessor were:

	Year ended December 31, 2019			Year ended December 31, 2018		
	Pre-policy change	Post-policy change	Impact	Pre-policy change	Post-policy change	Impact
Revenues	1,690	1,713	23	1,249	1,272	23
Depreciation and amortization	(438)	(473)	(35)	(300)	(335)	(35)
Income tax recovery (expense)	3	6	3	(93)	(90)	3
Net income (loss) impact			(9)			(9)

(d) Business combinations and goodwill:

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued, and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. When the excess is negative, a bargain purchase gain is recognized immediately into net income.

Identifiable assets acquired, and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

The Company elects on a transaction-by-transaction basis whether to measure a non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs and other acquisition costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Goodwill

After initial recognition, goodwill is not amortized, but is measured at cost less any accumulated impairment losses. Goodwill is tested for impairment annually, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired, at the cash-generating unit (CGU) level. For the purpose of impairment testing, goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the Company's CGUs that are expected to benefit from the acquisition.

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

For further discussion on impairment of goodwill, refer to the accounting policy for impairment of non-financial assets (note 2(p)).

2. Significant accounting policies, continued:

(e) Investments in joint arrangements:

Investments in joint operations

Capital Power has interests with other parties (the Joint Operators), whereby in each case the Joint Operators have a contractual arrangement that establishes the Joint Operators' rights to the assets and obligations for the liabilities of the arrangement and the Joint Operators' rights to the corresponding revenues and obligations for the corresponding expenses. These arrangements are considered to be joint operations.

In these situations, Capital Power recognizes its share of the joint operations' assets and liabilities in accordance with those associated rights and obligations, along with its share of the revenues from the output of the joint operation and its share of any expenses incurred. The accounting policies of these joint operations are aligned with the accounting policies of the Company.

Investment in joint venture

When the Company has an equal interest in a partnership with an external party where, by contractual agreement, each of the Partners effectively has rights to the net assets of the arrangement, the arrangement is considered to be a joint venture.

The Company's investment in a joint venture is accounted for under the equity method and recognized initially at cost. The carrying amount is increased or decreased to recognize the Company's share of the joint venture's total comprehensive income or loss after the date of acquisition. Distributions received from a joint venture reduce the carrying amount of the investment. The accounting policies of the joint venture are aligned with the accounting policies of the Company.

(f) Foreign currency translation:

Transactions in foreign currencies are translated to the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date, monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. The translation for other non-monetary assets is not updated from historical exchange rates unless they are carried at fair value. Revenues, other income and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

On consolidation, the assets and liabilities of U.S. operations that have a functional currency that is different from the Company's functional currency of Canadian dollars are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues, other income and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive loss as part of translation gains and losses.

(g) Government grant:

The Company's government grant reflects compensation to be received from the Province of Alberta (the Province) through 2030 related to the phase-out of coal-fired generation (see note 15). The Company recognizes government grants initially at fair value, and subsequently at amortized cost using the effective interest method and records such grants as a receivable and deferred revenue when there is reasonable assurance that they will be received and that the Company will comply with the conditions associated with the grant. The government grant receivable earns interest income until the final payment is received in 2030 and the associated deferred revenue is accreted until fully recognized into net income. The deferred revenue associated with the grant will be recognized in net income as other income on a straight-line basis through 2029 (formerly 2030) as this is the period over which costs will be incurred as a result of the 2029 phase-out of coal-fired generation. Interest income on the government grant receivable is recognized in net finance expense.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

2. Significant accounting policies, continued:

(h) Revenue recognition:

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operational groupings by facility category. Major types of revenues include energy revenues and emission credit revenues. Revenues excluded from the scope of IFRS 15 are disclosed as revenues from other sources and consist of contracts accounted for under IFRS 16 – Leases (note 2(i)) and IFRS 9 – Financial Instruments as described in the following table. Disaggregated revenues are disclosed in note 36.

Contracts with customers by operational groupings are as follows:

Operational grouping	**Description**
Alberta Commercial	The majority of the Company's interests in Alberta Commercial facilities are conducted through joint operations and the power is sold into energy markets on a merchant or non-contracted basis and included in energy revenue. Renewable Energy Credit (REC) sales from Halkirk are also within the scope of IFRS 15 and are described in the contracts with customers table below. The Company's portfolio optimization activities and associated revenues are excluded from the scope of IFRS 15.
Alberta Contracted	Power generation revenue from the Alberta Contracted facilities is managed under PPAs determined to be leases, which are accounted for under IFRS 16 and excluded from the scope of IFRS 15. Generation in excess of the committed capacity under these PPAs is managed as part of the Company's Alberta electricity portfolio optimization activities accounted for under IFRS 9 – Financial Instruments, and therefore is excluded from the scope of IFRS 15. By-product energy sales are included in energy revenues within the scope of IFRS 15.
Ontario and British Columbia Contracted	The majority of the power generated by the Ontario and British Columbia Contracted facilities is sold pursuant to long-term energy supply contracts and electricity purchase agreements which are included in energy revenues within the scope of IFRS 15. Steam production sales are also included in energy revenues within the scope of IFRS 15.
U.S. Contracted	Power generation revenue from the U.S. Contracted facilities that are managed under PPAs and emission credit revenues under fixed price contracts are included in energy revenues and emission credit revenues, respectively, within the scope of IFRS 15. Power generation revenues from U.S. contracted facilities that are managed under tolling agreements are considered to be leases and accounted for under IFRS 16 and excluded from the scope of IFRS 15. In addition, certain U.S. renewable facilities contain revenue swap arrangements that are accounted for under IFRS 9 – Financial Instruments which are also excluded from the scope of IFRS 15.

2. Significant accounting policies, continued:

(h) Revenue recognition, continued:

Contracts with customers

Revenue type	Nature, timing of satisfaction of performance obligations and significant payment terms
Energy revenues [1]	Electricity and natural gas supply contracts include a single performance obligation that is satisfied over time. Revenues from the sale of electricity and natural gas are recognized under the right to invoice practical expedient. The right to invoice practical expedient allows an entity to recognize revenue when it has the right to invoice the customer, if that amount corresponds directly with the value to the customer of the entity's performance completed to date. This occurs upon delivery or availability for delivery under the respective contracts. Customers are billed in the reporting period subsequent to when the performance obligation was met and settlements are in accordance with the agreed-upon contractual terms. In instances where the right to invoice practical expedient cannot be applied, energy revenues are recognized as the performance obligation is satisfied and measured under the output method which is based on energy generated, or availability, depending on the nature of the contracts with customers.
Emission credit revenues [1]	RECs generated by certain of the Company's facilities are sold to the respective customers under the terms of fixed price agreements. REC revenues are recognized when the performance obligations are satisfied at the specified transaction price. This occurs when physical control of RECs is transferred to the customer.

[1] The Company's contracts with customers are billed and paid in accordance with agreed-upon contractual terms. The Company has not incurred additional costs to obtain or fulfil the contracts with its customers. As at December 31, 2019 and 2018, the Company has not recorded any conditional unbilled receivables (contract assets) or customer advances and deposits (contract liabilities).

Derivative instruments

Revenues also include realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement of trading positions occurs and unrealized gains and losses are recognized as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenue

The Company records any gains resulting from sale and leaseback transactions as deferred revenue on its consolidated statements of financial position and amortizes the gain to depreciation and amortization on a straight-line basis over the lease term.

The government grant described in note 2(g) is recorded as deferred revenue. Accretion of the deferred revenue is recognized in net finance expense on the consolidated statements of income.

Monetary contributions received from external parties used to provide the Company with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized as the service is performed, or if an ongoing service is performed as part of an agreement, over the lesser of the life of the agreement and the life of the asset.

2. Significant accounting policies, continued:

(i) Leases or arrangements containing a lease:

Policy applicable from January 1, 2019

At inception of a contract, the Company assesses whether a contract is, or contains a lease. This assessment involves determining whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

Lessee

The Company recognizes a right-of-use asset and lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred, less any lease incentives received. The right-of-use asset is depreciated using the straight-line method from the commencement date to the end of the lease term, unless the lease transfers ownership of the underlying asset to the Company by the end of the lease term or the cost of the right-of-use asset reflects that the Company will exercise a purchase option. In that case, the right-of-use asset would be depreciated over the useful life of the underlying asset. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liability. Lease payments are recorded as interest expense and a reduction of the lease liability. Interest expense is recognized using the effective interest method. The Company is the lessee in contracts for various office, equipment, and land leases.

Lessor

At lease inception the Company determines whether the lease transfers substantially all of the risks and rewards incidental to ownership of the underlying asset. If this is the case, then the lease is classified as a finance lease; otherwise it is classified as an operating lease and revenues are recognized on a straight-line basis unless another method better represents the earnings process.

Policy applicable before January 1, 2019

Lessee

Where the Company has purchased goods or services as a lessee, and the lease has been determined to be an operating lease, rental payments are expensed as incurred over the life of the lease. Contractual arrangements the Company has entered into as a lessee that transfer substantially all of the risks and rewards of ownership to the Company are considered finance leases. The leased asset and lease obligation are recognized at the lower of fair value or the present value of the minimum lease payments. Lease payments are recorded as interest expense and a reduction of the lease liability. Interest expense is recognized using the effective interest method. The leased asset is depreciated over the shorter of the estimated useful life of the asset and the lease term.

(j) Non-derivative financial instruments:

Classification

The Company classifies its non-derivative financial instruments in the following categories: fair value through income or loss (FVTIL) or amortized cost.

The Company determines the classification of financial assets and liabilities at initial recognition. Classification of financial assets and liabilities is determined based on the business model by which assets and liabilities are managed and their cash flow characteristics.

Financial assets and liabilities are measured at FVTIL if they are classified as held for trading or are designated as such upon initial recognition. The Company may designate financial instruments as held at FVTIL when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

2. Significant accounting policies, continued:

(j) Non-derivative financial instruments, continued:

Measurement

Financial assets and liabilities at fair value through income or loss

Upon initial recognition transaction costs are recognized into net income as incurred. Financial assets and liabilities classified as held at FVTIL are measured at fair value with the changes in fair value reported in net income. Fair values are determined in the manner described in note 3. Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Financial assets and liabilities at amortized cost

Trade and other receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company's financial assets measured at amortized cost are comprised of cash and cash equivalents, trade and other receivables, and the government grant receivable.

Financial assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(p). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

The Company's financial liabilities measured at amortized cost are comprised of loans and borrowings and trade and other payables and are recognized on the date at which the Company becomes a party to the contractual arrangement. Liabilities are derecognized when the contractual obligations are discharged, cancelled or expired.

Financial liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest rate method.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company participates in tax-equity structures with project investors which have financed the construction of certain renewables projects. Such tax-equity structures are used in the U.S. to provide investors with access to U.S. income tax benefits such as investment tax credits, cash grants, production tax credits, and accelerated tax depreciation. In return for purchasing equity stakes in these projects, the project investors receive substantially all earnings, tax benefits and cash flows from the projects financed with a tax-equity structure until the projects have yielded an agreed upon target rate of return to the project investors. Immediately thereafter, the structures "flip" such that the Company receives the majority of earnings, tax benefits and cash flows from the projects financed with tax-equity structures. The date of the "flips" are dependent on the performance of the respective projects. In accordance with the substance of the contractual agreements, the amounts paid by the project investors for their equity stakes are classified as loans and borrowings on the consolidated statements of financial position until the respective "flip" dates of the projects. Subsequent to the "flip" dates, the project investor's equity investments will be accounted for as non-controlling interests. At all times, both before and after the projects "flip", the Company retains control over the projects financed with a tax-equity structure.

(k) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rates, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Classification and measurement

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting requirements are met, in which case such derivatives are classified as fair value through other comprehensive income (FVTOCI). Realized gains and losses on financial energy derivatives classified as FVTOCI are recorded in revenues or energy purchases and fuel. Realized gains and losses on interest rate derivatives classified as FVTOCI are recorded in finance expense. Realized gains and losses on foreign exchange derivatives classified as FVTOCI are recorded in foreign exchange gains or losses, or where the hedged transaction results in the recognition of net assets, those realized gains will flow through the initial carrying amount of those net assets. Unrealized gains and losses are recorded in other comprehensive income or loss. Fair values are determined in the manner described in note 3.

All derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative financial instruments assets or derivative financial instruments liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value. Derivative instruments are measured at FVTIL unless cash flow hedge accounting is used, in which case they are measured at FVTOCI. Embedded derivative instruments that are in scope of the standard are never separated from their host contract and are classified and measured as a combined instrument.

Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate, unrealized and realized gains and losses on financial interest rate derivatives are recorded in net finance expense and such gains and losses on financial foreign exchange derivatives are recorded in foreign exchange gains and losses.

Hedge accounting

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income (loss), while the ineffective portion is recognized in revenues, energy purchases and fuel, net finance expense or foreign exchange gain/loss as appropriate. The amounts recognized in other comprehensive income (loss) as cash flow hedging gains/losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur. The Company has not designated any fair value hedges at the date of the statement of financial position.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Company terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Hedge accounting, continued:

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive loss as part of cash flow hedging gains/losses and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income (loss) are recognized in net income in the same period as the corresponding gains or losses on the hedged item.

When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any remaining gains or losses associated with the hedging item that were previously recognized in other comprehensive income (loss) are recognized in net income in the period.

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations by reference to bid or asking price, as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(l) Property, plant and equipment

Property, plant and equipment is recorded at cost, net of accumulated depreciation and/or accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day to day repairs and maintenance costs are recognized into net income as incurred.

Depreciation

Depreciation is charged to net income on a straight-line basis over the estimated useful lives of each major component of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives. Land and construction work in progress are not depreciated. The estimated useful lives for major components of generation facilities and equipment range from 1 to 40 years. The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

2. Significant accounting policies, continued:

(l) Property, plant and equipment, continued:

Depreciation, continued:

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. Gains or losses on disposals are recognized on their own line within the consolidated statements of income while losses on retirements are recognized within depreciation and amortization.

(m) Intangible assets:

Capitalization

Intangible assets with definite lives are recorded at cost, net of accumulated amortization and/or accumulated impairment losses, if any. Intangible assets with definite lives are generally amortized over the related assets useful lives, as described below. Refer to note 18 for additional discussion on intangible assets.

Amortization

Amortization is charged to net income on a straight-line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating facility to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights are amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power assets or the term of the lease, whichever is shorter. The Company's purchased emission credits held for compliance purposes are not amortized, but are expensed as the associated benefits are realized. Such emission credits have definite lives as prescribed by their respective vintage years and any emission credits not used by the end of their lives would be expensed at that time.

The periods over which intangible assets are amortized are as follows:

Contract rights	7 to 40 years
Software	1 to 10 years

Estimated useful lives, methods of amortization and residual values are reviewed annually, and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized into net income as gains or losses on disposals.

(n) Development costs:

Development costs related to an acquisition or construction project are capitalized only if they can be measured reliably, future economic benefits are probable, and the Company intends to and has sufficient resources to complete development and use or sell the asset. Other development costs not meeting these criteria are recognized in income or loss as incurred. Capitalized development costs are measured at cost less accumulated amortization and accumulated impairment losses.

(o) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to reflect the costs of borrowing on its construction activities. Where project specific debt is not used to finance construction, interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets. Interest is only capitalized on assets which necessarily take a significant amount of time to get ready for their intended use.

2. Significant accounting policies, continued:

(p) Impairment of assets:

Non-financial assets

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (right-of-use assets, property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis, or more frequently if events or changes in circumstances indicate that the carrying amount may be impaired.

The asset's recoverable amount is the higher of its fair value less costs to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less costs to sell is determined using estimated market values utilizing actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

The Company's corporate assets, such as its computer networks and infrastructure, do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Any impairment loss is recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss is recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

As part of the Company's annual impairment testing, the East Windsor CGU which contains goodwill was tested for impairment and the carrying amount of the East Windsor CGU was within the range of its estimated recoverable amount for both the 2019 and 2018 annual impairment tests. As such, no impairments were required for the East Windsor CGU. Impairment testing was also completed on the Keephills 3 asset during 2019 as a result of its classification as an asset held for sale, with the resulting impairment disclosed in note 5. There were no other indicators to test non-financial assets for impairment during 2019 and 2018.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

Financial assets

The Company applies the "expected credit loss" (ECL) impairment model which applies to all financial assets. The Company considers the probability of default upon initial recognition of financial assets and whether there has been a significant increase in credit risk on an ongoing basis throughout each reporting period. The impairment methodology applied depends on whether there has been a significant increase in credit risk. The Company applies judgment to assess whether there is a significant increase in credit risk and considers available and reasonable forward-looking information in supporting this assessment.

2. Significant accounting policies, continued:

(p) Impairment of assets, continued:

Financial assets, continued

The Company has applied the simplified approach to providing for ECLs prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade and other receivables.

For all other financial assets, expected allowances are recognized as 12-month ECLs unless the credit risk of a financial asset has increased significantly, in which case lifetime ECL measurement applies. The Company has identified no financial instruments for which credit risk has increased significantly since initial recognition nor financial assets that are impaired as at December 31, 2019. Credit risk management procedures, including risk mitigation practices, are as described in note 30.

(q) Income taxes:

Income tax expense is comprised of current and deferred tax. Current and deferred tax is recognized in net income or loss, except to the extent that it relates to a business combination, or items recognized directly in equity, other comprehensive income (loss), or in loans and borrowings.

Current income taxes

Current income taxes comprise the expected tax payable or receivable on the taxable income or loss for the year and any adjustment to the tax payable or receivable in respect of previous years. The amount of current income tax payable or receivable is the best estimate of the tax amount expected to be paid or received that reflects uncertainty related to income taxes, if any. It is measured using tax rates enacted or substantively enacted at the reporting date. Current income taxes also include any tax arising from dividends. Current income tax assets and liabilities are only offset if certain criteria are met.

Deferred income taxes

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the respective amounts used for taxation purposes. Deferred income taxes are not recognized for:

- Temporary differences from the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither the taxable nor the accounting income;
- Temporary differences related to investments in subsidiaries, associates and joint arrangements to the extent that the Company is able to control the timing of the reversal of the temporary differences and it is probable that they will not reverse in the foreseeable future; and
- Temporary differences arising on the initial recognition of goodwill.

Deferred income tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable income will be available against which they can be used. Future taxable income is determined based on the Company's cash flow projections, which include estimates described in note 3. Deferred income tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable the related tax benefit will be realized; such reductions are reversed when the probability of future taxable income improves. Unrecognized deferred income tax assets are reassessed at each reporting date and recognized to the extent that it has become probable that future taxable income will be available against which they can be used.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted at the reporting date. The measurement of deferred income taxes reflects the tax consequences that would follow from the manner in which the Company expects, at the reporting date, to recover or settle the carrying amount of its assets and liabilities. Deferred income tax assets and liabilities are offset only if certain criteria are met.

2. Significant accounting policies, continued:

(r) Inventories:

Parts and other consumables and coal, principally all of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(s) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid investment-grade short-term investments with original terms to maturity of three months or less, and are measured at amortized cost using the effective interest method.

(t) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Unwinding of the discount rate on the decommissioning provisions is recorded in net finance expense over the estimated useful lives of the assets.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(u) Share-based payments:

The Company operates an equity-settled, share-based compensation plan where each stock option converts into one common share. The fair value of options granted for employee services is recognized over a three year vesting period as a compensation expense within staff costs and employee benefits expense and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

2. Significant accounting policies, continued:

(u) Share-based payments, continued:

The Company also operates share-based compensation plans for certain senior employees under a Performance Share Unit (PSU) Plan and a Restricted Share Unit (RSU) Plan. Share-based compensation for directors operates under a directors' Deferred Share Unit (DSU) Plan. The fair values of the amounts payable to employees/directors in respect of the PSU Plan, RSU Plan and the DSU Plan, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The PSU Plan and RSU Plan grant date fair values are determined using a binomial lattice valuation based on a five-day weighted average price of the Company's shares immediately prior to the grant, adjusted for estimated forfeitures and discounted using the risk-free interest rate. The DSU Plan grant date fair values are determined using the five-day weighted average price of the Company's shares immediately prior to the grant. The liability is re-measured to fair value at each reporting date and at the settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(v) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued.

3. Use of judgments and estimates:

The preparation of the Company's consolidated financial statements in accordance with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

Critical judgments in applying accounting policies

The main judgments that were used in preparing the Company's consolidated financial statements relate to:

Non-financial assets

The determination of CGUs was based on management's judgment, giving consideration to geographic proximity and shared risk exposure and risk management.

The Alberta CGU includes both Alberta Contracted and Alberta Commercial assets. The Alberta Contracted and Alberta Commercial assets are combined into one Alberta CGU for impairment testing purposes as the contracted period of the Alberta Contracted assets will be completed in 2020 and the majority of the remaining useful lives of these assets and the resulting future cash flows are now commercial in nature.

Identifying events or changes in circumstances that may indicate or cause an asset's carrying amount to exceed its recoverable amount requires judgment in assessing what events or circumstances would have such an impact.

Determining whether an arrangement contains a lease

The Company has exercised judgment in determining whether an arrangement contains a lease. This includes assessing whether a contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration for each agreement that was evaluated.

3. Use of judgments and estimates, continued:

Critical judgments in applying accounting policies, continued

Determining whether an arrangement contains a lease, continued

As noted in note 2(i), the Company has exercised judgment in determining whether the control of its generation assets which are subject to a PPA are transferred to the contracted purchaser under the PPA, in determining whether a lease exists. Details of those PPAs are provided in note 17.

Consolidation of subsidiaries that are less than wholly owned

The Company has exercised judgment in determining that a subsidiary is controlled by the Company even though the subsidiary is less than wholly owned as described in note 32.

Classification of joint arrangements structured through a separate vehicle

The Company has exercised judgment in determining the classification of joint arrangements structured through separate vehicles as described in note 33.

Operating segments

As noted in note 36, the Company operates in one reportable business segment. The Company has aggregated its operating segments into one reportable business segment as its operating segments have similar products, production processes, types of customers, product distribution methods, regulatory environments and economic characteristics. Each operating segment is involved with the generation and sale of electricity, which includes the process of turning various fuel sources into electricity and managing the revenues and costs of such electricity, including engaging in trading activities. The Company's customers tend to be large industrial and commercial customers, independent system operators and government owned or sponsored entities. Given the similar size and credit profiles of these counterparties, they are deemed to be similar types of customers. The method of distributing electricity is the same across all facilities, and none of the Company's entities are rate-regulated.

Key sources of estimation uncertainty

The main sources of estimation uncertainty in preparing the Company's consolidated financial statements relate to:

Measurement of fair values

A number of the Company's accounting policies and disclosures require the measurement of fair values, for both financial and non-financial assets and liabilities. Fair value represents the Company's estimate of the price that could be agreed on between knowledgeable and willing parties in an orderly arm's length transaction under no compulsion to act. Fair value measurements recognized in the consolidated statements of financial position, as well as those included within note disclosures, are categorized into levels within a fair value hierarchy based on the nature of the valuation inputs. Precedence is given to those fair value measurements calculated using observable inputs over those using unobservable inputs.

The determination of fair value requires judgment and is based on market information where available and appropriate. The following levels were established for each input:

- Level 1: Fair value is based on quoted prices (unadjusted) in active markets for identical instruments. Assets or liabilities classified in Level 1 include highly liquid short-term investments, and traded commodities obtained from active exchanges such as the New York Mercantile Exchange whereby the Company can obtain quoted prices for identically traded commodities.
- Level 2: Fair value is based on inputs other than quoted prices included in Level 1, which are either directly or indirectly observable at the reporting date. Level 2 includes those assets or liabilities that are valued using commonly used valuation techniques, such as a discounted cash flow model or the Black-Scholes option pricing model. Valuation models use inputs such as quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active but observable, and other observable inputs that are principally derived from or corroborated by observable market data for substantially the full term of the instrument.

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Measurement of fair values, continued

- Level 3: Fair value is based on unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the instrument. Level 3 includes assets or liabilities that are also valued using commonly used valuation techniques described in Level 2. However, some inputs used in the models may not be based on observable market data, but rather are based on the Company's best estimate from the perspective of a market participant.

The fair value measurement of an asset or liability is included in only one of the three levels, the determination of which is based upon the lowest level input that is significant to the derivation of the fair value. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment which will affect the placement within the fair value hierarchy levels.

Further information about the significant assumptions made in measuring fair values is included in the following notes:

- Note 4 – Business acquisitions;
- Note 5 – Genesee 3 and Keephills 3 swap transaction;
- Note 13 – Inventories - emissions credits;
- Notes 14 and 29 – Financial instruments;
- Note 24 – Provisions; and
- Note 28 – Share-based payments.

Depreciation and amortization

Depreciation and amortization allocate the cost of assets and their components over their estimated useful lives on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of the life characteristics of common assets. During 2019 and 2018, management assessed the major components of property, plant and equipment acquired in the respective years (see note 4) and estimated the useful lives of the respective components consistent with the Company's estimated useful lives for existing major components of similar generation facilities and equipment.

Income taxes

Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income. Details of tax losses expected to be utilized and the basis of utilization are provided in note 16.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Business acquisitions:

Acquisition of the Goreway Power Station

On June 4, 2019, a subsidiary of the Company acquired all of the equity interests in Goreway Power Station Holdings Inc., which owns the Goreway Power Station (Goreway). Goreway is an 875 megawatt (MW) natural gas combined cycle generation facility located in Brampton, Ontario. The purchase price consisted of (i) $405 million of total cash consideration, including working capital and other closing adjustments of $18 million, and (ii) the assumption of $590 million of asset level debt.

The allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values was finalized in the fourth quarter of 2019 and is as follows:

	June 4, 2019
Cash and cash equivalents	$ 20
Trade and other receivables	22
Inventories	9
Property, plant and equipment	814
Intangible assets	498
Trade and other payables	(18)
Loans and borrowings	(590)
Derivative financial instrument liabilities [1]	(104)
Provisions	(40)
Deferred tax liabilities	(206)
Fair value of net assets acquired	$ 405

[1] Interest rate swap agreements to hedge the interest on the assumed debt.

Goreway has a 20-year Accelerated Clean Energy Supply Contract expiring in June 2029 with the Ontario Independent Electricity System Operator. Goreway is strategically located in the Greater Toronto Area load centre making it an important asset in Ontario's electric system and, in combination with the Company's other Ontario natural gas assets, will provide operating and market synergies over time. The acquisition of Goreway supports the Company's growth strategy, fully meets the Company's investment criteria and contributes to the Company's dividend growth strategy through increased contracted cash flows through mid-2029.

The amount allocated to trade and other receivables for the acquisition represents both the estimated fair value and the gross contractual amounts receivable. As at December 31, 2019, all of the contractual cash flows pertaining to the acquired trade and other receivables have been collected.

The asset level debt assumed related to Goreway is a floating-rate bank facility based on prevailing market interest rates repayable quarterly with principal payments amortizing to 2029. The interest rate risk on this bank facility has been largely hedged through 2029 by interest rate swaps assumed as part of the acquisition covering 85% of the debt principal amount. The Company has elected to apply hedge accounting on these interest rate swaps. These swaps result in an effective fixed interest rate, on that portion of the assumed debt, of 7.4% (including a 1.4% stamping rate) per annum. The balance of the debt is subject to an interest rate based on the Canadian Dollar Offered Rate. The assumed bank facility matures in September 2020 at which time the hedging instruments also have a mandatory settlement in September of 2020.

Subsequent to year end, the Company extended both the credit facility and the hedging instruments to mature in January 2027 with an effective fixed interest rate, on the hedged portion of the assumed debt of 7.5% for the first four years (including a 1.2% stamping rate) and 7.7% for the latter three years (including a 1.4% stamping rate) per annum.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

4. Business acquisitions, continued:

Acquisition of the Goreway Power Station, continued:

The results of operations of Goreway are included in the Company's consolidated statements of income and statements of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statements of financial position. Since the acquisition date, $119 million of revenues and $1 million of net loss are included in the consolidated statements of income for the year ended December 31, 2019.

Had the acquisition occurred at January 1, 2019, the combined entity of the Company and the Goreway facility would have had a total of $1,806 million of revenues and $124 million of net income for the year ended December 31, 2019.

In conjunction with the acquisition of Goreway, for the year ended December 31, 2019, the Company incurred $2 million in acquisition costs which have been recorded on the Company's consolidated statements of income as other administrative expenses.

Acquisition of the Arlington Valley facility

On November 30, 2018, a subsidiary of the Company acquired all of the equity interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington Valley). Arlington Valley is a 580 MW natural gas-fired combined cycle power generation facility located in Phoenix, Arizona. The purchase price consisted of $399 million (US$303 million) in total cash consideration, including working capital and other closing adjustments of $3 million (US$3 million).

The purchase price allocation was finalized in 2019 and resulted in no change to the amounts recorded and disclosed at December 31, 2018.

The allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values is as follows:

	November 30, 2018
Inventories	$ 7
Property, plant and equipment	296
Intangible assets	113
Trade and other payables	(4)
Deferred revenue and other liabilities	(2)
Provisions	(11)
Fair value of net assets acquired	$ 399

This acquisition provides additional contracted cash flows, supports the Company's U.S. growth strategy and is consistent with the Company's technology and operating focus.

The results of operations of Arlington Valley are included in the Company's consolidated statements of income and statements of changes in equity from the date of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statements of financial position. Following the acquisition date in 2018, $6 million of revenues and $2 million of net loss were included in the consolidated statements of income for the year ended December 31, 2018.

Had the acquisition occurred at January 1, 2018, the combined entity of the Company and Arlington Valley would have had a total of $1,341 million of revenues for the year ended December 31, 2018.

In conjunction with the acquisition of Arlington Valley, for the year ended December 31, 2018, the Company incurred $2 million in acquisition costs which were recorded on the Company's statement of income as other administrative expenses.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Genesee 3 and Keephills 3 swap transaction:

Genesee 3 (G3) and Keephills 3 (K3) are coal and natural gas co-fired generating units in Alberta with a net capacity of 466 MW and 463 MW, respectively. Previously, both generating units were owned and operated under 50/50 Joint Venture Agreements between Capital Power and TransAlta Corporation (TransAlta).

In August 2019, the Company entered into an agreement to divest its 50% share of K3 to TransAlta, and to acquire TransAlta's 50% share of G3 for cash consideration, paid by Capital Power, of $10 million, subject to working capital and other closing adjustments. The consideration paid approximates the difference in fair value between the exchanged interests on the date of the transaction.

The transaction closed on October 1, 2019 at a pre-tax net loss of $249 million, with components of the net loss being recognized as disclosed in the table below.

		2019
Impairment of K3 net assets [1]	$	(401)
Accelerated recognition of coal compensation [2]		128
Gain on remeasurement of G3 net assets [3]		24
Total net loss on the transaction	$	(249)

[1] K3 net assets were classified as assets held for sale prior to the transaction closing and resulted in an impairment.

[2] Currently, the Company is receiving coal compensation from the province of Alberta related to the 2029 phase out of coal-fired generation that was originally determined by reference to the carrying amount of these assets. The coal compensation is being recognized annually through 2029 on a systematic basis that aligns with the depreciation expense related to coal-fired assets. The net reduction to the carrying amounts of the Company's coal-fired generation assets upon close of the transaction resulted in a one-time adjustment to accelerate the recognition of deferred government grant revenue that aligns with the reduction to the new lower carrying amount of coal-fired assets. The accelerated recognition of coal compensation is recognized in other income within the consolidated statements of income.

[3] The acquisition of the additional 50% of G3 was accounted for as a business combination and a gain was recognized on the Company's existing share of G3 as a result of the remeasurement of the carrying amount to its estimated fair value. This is recorded in gains on acquisition and disposal transactions within the consolidated statements of income.

Divestiture – Keephills 3

The Company tested the K3 disposal group for impairment during the third quarter of 2019, immediately prior to classifying those assets as held for sale, and in advance of the divestiture as described above. The carrying amount of the K3 disposal group was in excess of the estimated fair value of the proceeds to be received, resulting in a pre-tax impairment of $401 million within the Alberta CGU. The impairment was applied to the carrying amounts of the intangible assets and property, plant and equipment of the K3 disposal group.

For purposes of calculating the above impairment, the Company used the fair value less costs to sell of K3 as the recoverable amount of the assets. The fair value less costs to sell was established by the transaction agreement described above based on the fair value of G3, net of the $10 million payment made by the Company, less the Company's estimate of the directly attributable incremental costs related to the disposal. The determination of the G3 fair value is described below.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Genesee 3 and Keephills 3 swap transaction, continued:

Divestiture – Keephills 3, continued

The carrying amounts of the assets and liabilities of the K3 disposal group at the time of disposal, net of the impairment, were as follows:

	October 1, 2019
Trade and other receivables	$ 2
Inventories	8
Other assets	2
Property, plant and equipment	270
Intangible assets	34
Deferred revenue and other liabilities	(5)
Provisions	(15)
Carrying amount of net assets disposed	$ 296

Acquisition of additional 50% interest in Genesee 3

On October 1, 2019, the Company acquired an additional 50% interest in G3 increasing its total ownership to 100%. The purchase price consisted of (i) $10 million of total cash consideration, (ii) the exchange of Capital Power's 50% interest in K3 of $301 million as described above, and nominal working capital and other closing adjustments. The allocation of the purchase price to the assets acquired and liabilities assumed on acquisition of the additional 50% share of G3 based on their estimated fair values is as follows:

	October 1, 2019
Cash and cash equivalents	$ 3
Trade and other receivables	1
Inventories	8
Property, plant and equipment	290
Intangible assets [4]	25
Provisions	(16)
Fair value of net assets acquired	$ 311

[4] Intangible assets include $23 million relating to contract rights related to the acquired assets, for which capital contributions were previously made by TransAlta. Prior to the close of the transaction, those contributions were recorded within deferred revenue and other liabilities. Immediately following the close of the transaction, the acquired intangible assets and the previously recorded deferred revenue and other liabilities became offsetting intercompany balances and have been eliminated from the Company's statements of financial position.

Measurement of fair values

The fair value measurement of the additional 50% share of G3 is categorized in Level 3 of the fair value hierarchy based on inputs used in the discounted cash flow model. The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures to the end of G3's useful life in 2039 which assumes a full conversion to natural gas.

These estimates reflect past experience and the Company's current view of future generating capacity, fuel sources and fuel pricing. Consideration is given to externally available information related to future electricity and fuel pricing inputs when developing assumptions and such external information is used to validate the Company's current view of future pricing assumptions. These external sources of information include information from third party advisory and research firms serving the industry. Alberta power pricing and natural gas pricing assumptions used in the modelling above are classified in Level 3 of the fair value hierarchy. The table below presents ranges for the Level 3 inputs over the useful life of G3:

Alberta power prices ($/MWh)	$ 57.80 to $ 85.30
Natural gas prices ($/GJ)	$ 1.53 to $ 4.02

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

6. Other income:

Year ended December 31	2019	2018
Contributions and grants	$ 9	$ 10
Government compensation (note 15)	181	51
Production tax credits	36	22
Modified Accelerated Cost Recovery System depreciation	21	58
Other	3	4
Other income	$ 250	$ 145

7. Expenses:

Year ended December 31	2019	2018 (note 2(c))
Included in energy purchases and fuel		
Recovery of flow-through expenses related to the Genesee 1 and 2 PPAs	$ (105)	$ (91)
Included in staff costs and employee benefits expense		
Share-based payments (note 28)	16	14
Post-employment defined contribution plan expense	8	7
Post-employment defined benefit plan expense	3	3
Recovery of flow-through expenses related to the Genesee 1 and 2 PPAs	-	(1)
	27	23
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 19)	356	309
Amortization of intangible assets (note 18)	105	24
Depreciation of right-of-use assets (note 17)	8	-
Other	4	2
	$ 473	$ 335

8. Net finance expense:

Year ended December 31	2019	2018
Interest expense		
Interest on loans and borrowings	$ 146	$ 115
Capitalized interest	(13)	(5)
Total interest expense	133	110
Other finance expense		
Accretion on decommissioning provisions (note 24)	6	5
Interest on lease liabilities	5	1
Accretion on deferred government grant revenue	17	16
Interest on long-term government grant receivable	(15)	(16)
Other	10	7
Net finance expense	$ 156	$ 123

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

9. Income tax (recovery) expense:

Year ended December 31	2019	2018 (note 2(c))
Current income tax		
Current income tax expense	$ 55	$ 22
Recognition of previously unrecognized tax benefits	-	(3)
Adjustments for prior periods	(1)	(1)
Total current income tax expense	54	18
Deferred income tax		
Origination and reversal of temporary differences	(6)	77
Change in statutory tax rate [1]	(51)	-
Recognition of previously unrecognized tax benefits	(3)	(9)
Change in write-downs of deferred tax assets	-	4
Total deferred income tax (recovery) expense	(60)	72
Income tax (recovery) expense	$ (6)	$ 90

Reconciliation of effective income tax rate

Year ended December 31	2019	2018 Note 2(c))
Income before tax	$ 113	$ 348
Income tax at the statutory rate of 26.5% (2018 - 27.0%) [1]	30	94
Increase (decrease) resulting from:		
Amounts attributable to non-controlling interests and tax equity interests [2]	18	29
Change in unrecognized tax benefits	21	(8)
Non-taxable amounts	(5)	(29)
Adjustments for prior periods	1	(2)
Statutory and other rate differences	(63)	3
Reversal of deferred tax expense related to temporary difference on investment in subsidiary	(11)	-
Other	3	3
Income tax (recovery) expense	$ (6)	$ 90

[1] On June 28, 2019, as a result of the Alberta Government's Bill 3 - Job Creation Tax Cut Act, the Alberta corporate income tax rate was reduced from 12% to 8% over 4 years. Accordingly, the 2019 statutory tax rate is 26.5% and will decrease further to 25% for the 2020 year, to 24% for the 2021 year, and to 23% for the 2022 year. Due to this tax rate decrease, the Canadian deferred tax assets and liabilities were re-measured, resulting in the recognition of a deferred income tax recovery of $51 million during the year ended December 31, 2019.

[2] During the year ended December 31, 2018, the Company recorded a non-taxable, non-cash, one-time amount attributable to tax-equity interests in Bloom Wind of $15 million (US$11 million) relating to the renegotiation of certain commercial terms within the Bloom Wind tax equity agreement. This renegotiation resulted from the reduction of the U.S. Federal corporate tax rate which was effective January 1, 2018. The total amount recorded reflects an increase in other income of $44 million (US$33 million) net of an increase in income tax expense of $29 million (US$22 million).

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

10. Earnings per share:

The earnings and weighted average number of common shares used in the calculation of basic and diluted earnings per share are as follows:

Year ended December 31	2019	2018 note (2(c))
Income for the period attributable to shareholders	$ 125	$ 265
Preferred share dividends [1]	(49)	(42)
Earnings available to common shareholders	$ 76	$ 223
Weighted average number of common shares	104,297,420	102,976,162
Basic earnings per share	$ 0.73	$ 2.17
Weighted average number of common shares	104,297,420	102,976,162
Effect of dilutive share purchase options	716,742	355,639
Diluted weighted average number of common shares	105,014,162	103,331,801
Diluted earnings per share	$ 0.72	$ 2.16

[1] Includes preferred share dividends declared and related taxes.

11. Cash and cash equivalents:

As at December 31	2019	2018
Cash on deposit	$ 100	$ 99
Cash equivalents	148	83
	$ 248	$ 182

Cash and cash equivalents includes $16 million (2018 - $63 million) related to margin posted with exchange counterparties as a result of the Company's commodity trading activity. As part of its collateral requirements, one of the Company's exchange counterparties updates its bank margin accounts daily, by recording fair value changes on unsettled derivative financial instruments outstanding with the Company.

Included in the Company's cash and cash equivalents is its proportionate share of its rights to cash and cash equivalents, which are restricted to use within its joint operations and tax equity interests of $22 million (2018 - $48 million).

12. Trade and other receivables:

As at December 31	2019	2018 (note 2(c))
Accrued revenues	$ 199	$ 161
Trade receivables	36	110
Net trade receivables	235	271
Proceeds on disposal of joint venture interest receivable (note 33)	-	90
Government grant receivable (note 15)	53	52
Income taxes recoverable	5	2
Prepayments	41	23
	$ 334	$ 438

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 30.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Inventories:

As at December 31	2019	2018
Parts and other consumables	$ 120	$ 105
Emission credits	67	71
Coal	16	24
	$ 203	$ 200

Inventories expensed upon usage for the year ended December 31, 2019 of $166 million (2018 - $149 million) were charged to energy purchases and fuel, and other raw materials and operating charges. Emission credits held for trading are carried at fair value as estimated by quoted market prices available as of the valuation date. Details of the valuation techniques used in determining the fair values are described in note 14. Inventory write-downs of $2 million were recognized in the year ended December 31, 2019 (2018 - nil). There were no reversals of previous write-downs recognized in the year ended December 31, 2019 (2018 - nil). As at December 31, 2019, no inventories were pledged as security for liabilities (2018 - nil).

14. Derivative financial instruments and hedge accounting:

Derivative instruments assets and liabilities are primarily used for risk management purposes as described in note 30 and consist of the following:

	December 31, 2019				
	Energy and emission allowances		Interest rate		
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ -	$ 81	$ -	$ 2	$ 83
Non-current	-	151	-	-	151
Derivative instruments liabilities:					
Current	(12)	(85)	(83)	-	(180)
Non-current	(11)	(107)	-	-	(118)
Net fair value	$ (23)	$ 40	$ (83)	$ 2	$ (64)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(7)	(14)			
Gigajoules of natural gas purchased[1]		181			
Gigajoules of natural gas basis swaps[1]		179			
Metric tons of emission allowances		4			
Number of renewable energy credits		(1)			
Interest rate swaps			$ 763	$ 100	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 13.0	0.8 to 0.9	0.9	

[1] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Derivative financial instruments and hedge accounting, continued:

	December 31, 2018				
	Energy and emission allowances		Interest rate	Foreign exchange	
	cash flow hedges	non-hedges	cash flow hedges	non-hedges	Total
Derivative instruments assets:					
Current	$ 5	$ 60	$ -	$ 12	$ 77
Non-current	6	76	-	-	82
Derivative instruments liabilities:					
Current	(9)	(73)	(7)	(1)	(90)
Non-current	(2)	(112)	-	-	(114)
Net fair value	$ -	$ (49)	$ (7)	$ 11	$ (45)
Net notional buys (sells) (millions):					
Megawatt hours of electricity	(7)	(14)			
Gigajoules of natural gas purchased[2]		69			
Gigajoules of natural gas basis swaps[2]		69			
Metric tons of emission allowances		4			
Number of renewable energy credits		(14)			
Bond forwards			$ 250		
Interest rate swaps			$ 200		
Forward currency buys (U.S. dollars)				$ 117	
Range of remaining contract terms in years	0.1 to 4.0	0.1 to 14.0	0.1 to 0.9	0.7 to 0.9	

[2] The Company's natural gas trading strategy employs future purchase derivative instruments as well as basis swaps pertaining to certain of the future purchase derivative instruments, to manage its exposure to commodity price risk.

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices dependent on which is most representative of fair value in the circumstances, in the principal market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until inputs become observable. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material. As at December 31, 2019 and 2018, the Company classified financial instruments under Level 2 and Level 3 of the fair value hierarchy described in note 3.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Derivative financial instruments and hedge accounting, continued:

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in other comprehensive income and net income were:

	2019		2018	
	Unrealized (losses) gains	Realized (losses) gains	Unrealized gains (losses)	Realized (losses) gains
Energy cash flow hedges	$ (23)	$ (12)	$ 47	$ (19)
Energy and emission allowances non-hedges	119	56	(70)	68
Interest rate cash flow hedges[3]	1	(2)	(7)	-
Interest rate non-hedges	2	-	-	-
Foreign exchange non-hedges	(11)	8	(21)	34

[3] Interest rate cash flow hedges of $450 million were settled in the year ended December 31, 2019 for a total loss of $18 million which includes $17 million deferred within accumulated other comprehensive (loss) income to be reclassified to net income in future periods within the associated net finance expense pertaining to the hedged note offering.

Realized and unrealized gains and losses relate only to derivative financial instruments. The following realized and unrealized gains and losses are included in the Company's statements of income for the years ended December 31, 2019 and 2018:

	2019	2018
Revenues	$ 71	$ 55
Energy purchases and fuel	92	(76)
Foreign exchange (loss) gain	(3)	13

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices and interest rate risk relating to future borrowings. For the year ended December 31, 2019, $1 million of losses were realized within net finance expense pertaining to the ineffective portion of hedging derivatives (2018 – nil).

Net after tax gains and losses related to derivative instruments designated as energy and interest rate cash flow hedges are expected to settle and be reclassified to net income in the following periods:

As at December 31	2019
Within one year	$ (7)
Between one and five years	(6)
After five years	1
	$ (12)

15. Government compensation:

In 2016, the Company reached an agreement with the Government of Alberta (GoA) related to the 2030 phase-out of coal-fired generation. As compensation for the capital that the Company invested in coal generating assets that will be stranded effective December 31, 2030, the Company was to receive cash payments from the Province of $52 million annually for 14 years, commencing July 31, 2017, for a total of $734 million. This future compensation stream has been recognized as a government grant, recorded within deferred revenue and other liabilities and was originally being recognized into net income through 2030. Additionally, the compensation to be received has been recognized as a government grant receivable which will be drawn down as cash payments are received.

Amendments to the Federal Government's Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations were finalized in December 2018, which mandate the phase-out of coal-fired generation by December 31, 2029. Accordingly, the Company shortened the useful lives of its coal-fired assets to 2029 and adjusted the recognition of the government grant deferred revenue to align with the depreciation of the coal-fired assets. In the fourth quarter of 2019, the Genesee 3 and Keephills 3 swap transaction (note 5) resulted in a net reduction to the carrying amounts of the Company's coal-fired assets which resulted in a one-time adjustment to accelerate the recognition of deferred government grant revenue that aligns with the reduction to the new lower carrying amount of coal-fired assets.

The conditions on the government grant include the Company agreeing to cease coal-fired emissions on or before December 31, 2030 and the Company continuing to participate in and make a minimum annual investment of $1 million in the Alberta electricity market, with a minimum total investment in the Alberta electricity market of $70 million by the end of 2030. This total required investment has been exceeded with the Company's investment in the first phase of the Whitla Wind project (note 34(b)). Additional conditions include the Company supporting the local communities surrounding the coal facilities through 2030, and fulfilling its pension and other commitments to employees.

The GoA conducted an audit in 2017 on the calculation of net book values driving the compensation payments and has withheld approximately $2.7 million from each of the 2017, 2018 and 2019 payments on the basis of an alleged "implied term" of the Off-Coal Agreement. Capital Power believes there was no such implied term and has therefore sued the GoA for recovery of the withheld amounts and specific performance for future payments. Although the above noted legal action is being pursued, the Company has reduced the amounts recorded related to the compensation stream to reflect the uncertainty around the withheld portion of the payments. This has resulted in a reduction of $1 million to the government compensation amount recorded in other income to $51 million for each of 2019, 2018 and 2017. The respective deferred revenue and government grant receivable amounts have likewise been adjusted and now reflect total payments over the 14-year term of $712 million.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

16. Deferred tax:

Movement of deferred tax balances

	As at January 1, 2019 (note 2(c))	Recognized in net income	Recognized directly in other compre-hensive income	Amounts relating to acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2019	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 79	$ (26)	$ (2)	$ -	$ 18	$ (18)	$ 51	$ 51	$ -
Property, plant and equipment	(573)	41	4	(117)	-	-	(645)	-	(645)
Intangible assets	38	16	-	(125)	-	-	(71)	55	(126)
Deferred partnership income	(9)	49	-	-	-	-	40	40	-
Derivative financial instruments	10	(31)	5	26	-	-	10	68	(58)
Share issue costs and deferred financing charges	3	-	-	-	1	-	4	4	-
Deferred revenue and other liabilities	190	(70)	(1)	-	-	-	119	119	-
Right-of-use assets	(22)	1	-	-	-	-	(21)	-	(21)
Government grant receivable	(138)	26	-	-	-	-	(112)	-	(112)
Other financial assets	(16)	13	-	-	-	-	(3)	-	(3)
Decommissioning provisions	69	5	(1)	10	-	-	83	83	-
Goodwill	9	(1)	-	-	-	-	8	8	-
Prepaid reclamation amounts	(18)	3	-	-	-	-	(15)	-	(15)
Other provisions	20	(1)	1	-	-	-	20	20	-
Loans and borrowings	17	(6)	-	-	-	-	11	11	-
Other assets	7	(1)	-	-	-	-	6	6	-
Trade and other receivables	2	(1)	-	-	-	-	1	1	-
Trade and other Payables	(1)	1	-	-	-	-	-	-	-
Lease liabilities	25	1	-	-	-	-	26	26	-
Arising from disposal of joint venture	(41)	41	-	-	-	-	-	-	-
Deferred tax (liabilities) assets	$ (349)	$ 60	$ 6	$ (206)	$ 19	$ (18)	$ (488)	$ 492	$ (980)
Set-off of tax							-	(468)	468
Net deferred tax (liabilities) assets							$ (488)	$ 24	$ (512)

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

16. Deferred tax, continued:

Movement of deferred tax balances, continued

	As at January 1, 2018 (note 2(c))	Recognized in net income (note 2(c))	Recognized directly in other compre-hensive income	Amounts relating to acquisitions and disposals	Recognized directly in equity	Reclassified from equity to net income	As at December 31, 2018 (note 2(c))	Deferred tax assets	Deferred tax liabilities (note 2(c))
Losses carried forward	$ 78	$ (1)	$ 4	$ -	$ 16	$ (18)	$ 79	$ 79	$ -
Property, plant and equipment	(506)	(66)	(4)	3	-	-	(573)	-	(573)
Intangible assets	43	(6)	-	1	-	-	38	40	(2)
Deferred partnership income	(6)	(3)	-	-	-	-	(9)	-	(9)
Derivative financial instruments	-	20	(10)	-	-	-	10	48	(38)
Share issue costs and deferred financing charges	2	1	-	-	-	-	3	3	-
Equity-accounted investments	(7)	13	(2)	(4)	-	-	-	-	-
Deferred revenue and other liabilities	182	(3)	1	-	11	-	191	191	-
Government grant receivable	(147)	9	-	-	-	-	(138)	-	(138)
Other financial assets	(14)	(2)	-	-	-	-	(16)	-	(16)
Decommissioning provisions	61	7	1	-	-	-	69	69	-
Goodwill	9	(1)	1	-	-	-	9	9	-
Prepaid reclamation amounts	(18)	-	-	-	-	-	(18)	-	(18)
Other provisions	19	2	(1)	-	-	-	20	20	-
Loans and borrowings	19	(2)	-	-	-	-	17	17	-
Other assets	7	-	-	-	-	-	7	7	-
Trade and other receivables	-	2	-	-	-	-	2	2	-
Trade and other Payables	-	(1)	-	-	-	-	(1)	-	(1)
Arising from disposal of joint venture	-	(41)	-	-	-	-	(41)	-	(41)
Deferred tax (liabilities) assets	$ (278)	$ (72)	$ (10)	$ -	$ 27	$ (18)	$ (351)	$ 485	$ (836)
Set-off of tax							-	(426)	426
Net deferred tax (liabilities) assets							$ (351)	$ 59	$ (410)

Unrecognized deferred tax assets

Deferred tax assets have not been recognized on the following items:

As at December 31	2019	2018
Non-capital losses	$ 57	$ 72
Deductible temporary differences with no expiry	187	82
	$ 244	$ 154

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

16. Deferred tax, continued:

Tax losses carried forward

	2019		2018	
	Tax losses	Expiry dates	Tax losses	Expiry dates
Unrecognized tax losses carried forward	$ 57	2028-2039	$ 72	2028-2038

As at December 31, 2019, the Company has non-capital losses carried forward of $283 million (2018 - $410 million), of which $245 million (US$189 million) (2018 - $310 million (US$227 million)) relates to U.S. subsidiaries.

17. Leases:

Lessee

Right-of-use assets

	Land	Offices	Equipment	Total
Balance, January 1, 2019	$ 51	$ 28	$ 20	$ 99
Additions	4	-	-	4
Depreciation	(4)	(3)	(1)	(8)
Balance, December 31, 2019	$ 51	$ 25	$ 19	$ 95

Lease liabilities

The following table presents amounts recognized in the consolidated statements of income:

Year ended December 31,	2019
Income from rental and sub-leasing	$ 1
Interest on lease liabilities	(5)
Variable lease payments not included in the measurement of lease liabilities	(5)

As at December 31, 2019, expenses related to short-term and low-value leases was nil.

Lessor

Facilities under operating leases

The Genesee units 1 and 2, Island Generation, Decatur Energy and Arlington Valley power generation facilities are accounted for as assets under operating leases.

As at December 31, 2019, the cost of such property, plant and equipment was $2,030 million (December 31, 2018 - $2,006 million), less accumulated depreciation of $513 million (December 31, 2018 - $433 million).

The minimum future rental payments to be received on these PPAs are:

As at December 31	2019
2020	$ 168
2021	124
2022	117
2023	46
2024	47
Thereafter	49
Total	$ 551

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

18. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Total
Cost							
As at January 1, 2018	$ 29	$ 55	$ 49	$ 165	$ 129	$ 55	$ 482
Additions	53	-	-	-	5	-	58
Additions from business acquisitions (note 4)	-	102	-	11	-	-	113
Additions into service	(28)	-	-	28	-	-	-
Retirements and other disposals	-	-	-	-	(63)	-	(63)
Transfers to held for sale emission credits inventory	-	-	-	-	(24)	-	(24)
Foreign currency translation adjustments	3	7	1	2	-	-	13
As at December 31, 2018	$ 57	$ 164	$ 50	$ 206	$ 47	$ 55	$ 579
Additions	12	-	-	2	12	-	26
Additions from business acquisition (note 4)	-	498	-	-	-	-	498
Additions into service	(32)	-	-	28	-	4	-
Retirements and other disposals	(8)	(52)	-	-	(25)	(5)	(90)
Impairment (note 5)	-	-	-	(47)	-	-	(47)
G3 and K3 swap transaction (note 5)	(4)	-	-	(52)	-	(1)	(57)
Transfers within intangible assets	-	-	11	(11)	-	-	-
Transfers to property, plant & equipment	(3)	-	-	-	-	-	(3)
Transfers to held for sale emission credits inventories	-	-	-	-	(9)	-	(9)
Foreign currency translation adjustments	(1)	(6)	(1)	(2)	-	-	(10)
As at December 31, 2019	$ 21	$ 604	$ 60	$ 124	$ 25	$ 53	$ 887
Accumulated amortization							
As at January 1, 2018	$ -	$ (12)	$ (11)	$ (26)	$ -	$ (32)	$ (81)
Amortization (note 7)	-	(8)	(3)	(8)	-	(5)	(24)
Foreign currency translation adjustments	-	(1)	-	-	-	-	(1)
As at December 31, 2018	$ -	$ (21)	$ (14)	$ (34)	$ -	$ (37)	$ (106)
Amortization (note 7)	-	(91)	(2)	(8)	-	(4)	(105)
Retirements and other disposals	-	52	-	-	-	5	57
G3 and K3 swap transaction (note 5)	-	-	-	24	-	1	25
Foreign currency translation adjustments	-	2	-	-	-	-	2
As at December 31, 2019	$ -	$ (58)	$ (16)	$ (18)	$ -	$ (35)	$ (127)
Net book value							
As at January 1, 2018	$ 29	$ 43	$ 38	$ 139	$ 129	$ 23	$ 401
As at December 31, 2018	$ 57	$ 143	$ 36	$ 172	$ 47	$ 18	$ 473
As at December 31, 2019	$ 21	$ 546	$ 44	$ 106	$ 25	$ 18	$ 760

Contract rights include acquired management and operations agreements and a 20-year agreement whereby the Company will sell RECs produced by the Halkirk Wind Project to a third party.

Other rights include the cost of land lease agreements for use in wind power projects in Alberta and Ontario and wind and solar power projects in the United States, as well as coal supply access rights relating to the Keephills 3 Project (until close of the G3 and K3 swap transaction (note 5)) and pipeline access rights relating to Arlington Valley.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

18. Intangible assets, continued:

Impairment

An impairment of $47 million on intangible assets, related to the K3 disposal group, was recognized during the year ended December 31, 2019 (2018 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2019 (2018 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2019 or 2018.

Restrictions on assets

There are no charges over the Company's intangible assets.

19. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment (note 2(c))	Total
Cost				
As at January 1, 2018	$ 64	$ 118	$ 6,148	$ 6,330
Additions	297	1	13	311
Additions into service	(232)	-	232	-
Retirements and other disposals	-	-	(58)	(58)
Acquisitions through business acquisitions (note 4)	6	3	287	296
Transfers to inventory	(4)	-	-	(4)
Revisions to decommissioning costs (note 24)	-	-	3	3
Foreign currency translation adjustments	5	-	105	110
As at December 31, 2018	$ 136	$ 122	$ 6,730	$ 6,988
Additions	622	-	36	658
Additions into service	(403)	-	403	-
G3 and K3 swap transaction (note 5)	(2)	-	(150)	(152)
Retirements and other disposals	(5)	-	(103)	(108)
Acquisition through business acquisition (note 4)	13	26	775	814
Impairment (note 5)	-	-	(354)	(354)
Transfers to right-of-use assets	-	-	(21)	(21)
Other transfers	(3)	-	1	(2)
Revisions to decommissioning costs (note 24)	-	-	24	24
Foreign currency translation adjustments	(8)	-	(76)	(84)
As at December 31, 2019	$ 350	$ 148	$ 7,265	$ 7,763
Accumulated depreciation				
At January 1, 2018	$ -	$ -	$ (1,364)	$ (1,364)
Depreciation (note 7)	-	-	(309)	(309)
Retirements and other disposals	-	-	58	58
Foreign currency translation adjustments	-	-	(17)	(17)
As at December 31, 2018	$ -	$ -	$ (1,632)	$ (1,632)
Depreciation (note 7)	-	-	(356)	(356)
G3 and K3 swap transaction (note 5)	-	-	194	194
Retirements and other disposals	-	-	101	101
Transfers to right-of-use assets	-	-	7	7
Foreign currency translation adjustments	-	-	12	12
As at December 31, 2019	$ -	$ -	$ (1,674)	$ (1,674)
Net book value				
As at January 1, 2018	$ 64	$ 118	$ 4,784	$ 4,966
As at December 31, 2018	$ 136	$ 122	$ 5,098	$ 5,356
As at December 31, 2019	$ 350	$ 148	$ 5,591	$ 6,089

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

19. Property, plant and equipment, continued:

Impairment

An impairment of $354 million on property, plant and equipment, related to the K3 disposal group, was recognized during the year ended December 31, 2019 (2018 - nil). No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2019 (2018 - nil).

Capitalized borrowing costs

Details of borrowing costs capitalized as part of property, plant and equipment are provided in note 8. The average borrowing rate used to capitalize interest during the year was 4.57% (2018 – 4.45%) for projects financed using general borrowings. For the years ended December 31, 2019 and 2018, there were no projects financed using specific borrowings that were included as part of property, plant and equipment.

Restrictions on assets

Details of charges over land, plant and equipment are provided in note 21.

20. Trade and other payables:

As at December 31	2019	2018 (note 2(c))
Operating accruals	$ 137	$ 122
Trade payables	63	57
Dividends payable	50	46
Accrued interest	19	15
Taxes payable	32	4
	$ 301	$ 244

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

21. Loans and borrowings:

	Effective interest rate	December 31, 2019	December 31, 2018
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.85% due in 2019	4.96%	$ -	$ 250
Issued by CPC, at 5.28% due in 2020	5.34%	251	300
Issued by CPC, at 4.28% due in 2024	4.37%	450	450
Issued by CPC, at 4.99% due in 2026	5.07%	300	-
Issued by CPC, at 4.42% due in 2030	4.49%	275	-
		1,276	1,000
CPC private placement, payable semi-annually			
Issued by CPC, at 3.85% due in 2026	3.85%	160	160
Issued by CPC, at 4.56% due in 2029	4.64%	210	-
Issued by CPC, at 4.72% due in 2031	4.79%	65	-
Issued by CPC, at 4.96% due in 2034	5.02%	50	-
		485	160
CPLP unsecured senior notes, payable semi-annually			
US$230, at 5.21% due in 2021	5.29%	299	314
US$65, at 5.61% due in 2026	5.67%	84	89
		383	403
CPLP non-recourse financing, payable quarterly			
Goreway Power Station, $590 at floating rates, due in 2020	3.48%	563	-
Joffre Cogeneration Project, at 8.59%, repaid in 2019	8.31%	-	9
East Windsor Cogeneration Project, at 6.28%, due in 2029	6.23%	128	138
Macho Springs, US$50 at 6.90%, due in 2031	7.00%	52	59
		743	206
Tax-equity financing, payable quarterly [1]			
Bloom Wind, US$100		130	155
New Frontier Wind, US$79		102	130
Committed credit facilities			
CPLP US$246, at floating rates, due in 2024	3.46%	319	218
CPC, at floating rates, due 2019	3.61%	-	396
		551	899
Total debt payable		3,438	2,668
Less: current portion		857	456
		2,581	2,212
Less: deferred debt issue costs		25	21
		$ 2,556	$ 2,191

[1] Effective interest rate on tax-equity financing reflects the internal rate of return on the respective tax equity investments.

21. Loans and borrowings, continued:

Medium-term note issuances

On January 23, 2019, the Company issued $300 million of unsecured medium-term notes due in 2026 with interest payable semi-annually at 4.986% commencing on July 23, 2019.

On November 8, 2019, the Company issued $275 million of unsecured medium-term notes due in 2030 with interest payable semi-annually at 4.424% commencing on August 8, 2020.

$325 million private placement debt financing

On June 12, 2019, the Company completed a $325 million private placement of senior notes consisting of three tranches with 10, 12 and 15-year terms. The 10-year tranche has a principal amount of $210 million that matures in June 2029 with a coupon rate of 4.56%. The 12-year tranche has a $65 million principal amount and matures in June 2031 with a coupon rate of 4.72%. The 15-year tranche has a $50 million principal amount and matures in June 2034 with a coupon rate of 4.96%.

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. The debt was settled early and has been fully repaid as of December 31, 2019.

East Windsor Cogeneration Project financing represents Series 1 Senior bonds issued by the Company. The debt is secured by a charge against project assets which have a carrying amount of $145 million

Macho Springs financing represents loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $76 million.

Goreway Power Station financing represents the asset level debt assumed in the acquisition (note 4) . The debt is secured by a charge against the assets of the facility which have a carrying amount of $523 million.

Tax-equity financing

Bloom Wind and New Frontier Wind tax-equity financing represents the initial equity investments made by the project investors, on the respective projects, adjusted for earnings, tax benefits and cash distributions paid to date. The maturity dates of these obligations are subject to change and are driven by the dates on which the project investor reaches the agreed upon target rate of return.

On December 21, 2018, the Company commenced commercial operation of New Frontier Wind. On December 31, 2018, the Company received $130 million (US$95 million) in financing from J.P. Morgan in exchange for Class A interests of a subsidiary of the Company. The Company incurred issue costs of $4 million (US$3 million) associated with the financing.

Committed credit facilities

Unsecured credit facilities include a $700 million syndicated credit facility and an unsecured club credit facility of $300 million committed to July 9, 2024. As at December 31, 2019, the Company had no Canadian loans (2018 – $246 million), U.S. loans of $319 million (US$246 million) (2018 - $218 million (US$160 million)) and letters of credit of $50 million (2018 - $99 million) outstanding under these facilities as described in note 35.

Bilateral unsecured demand credit facilities are available to CPC and include $430 million for the issuance of letters of credit and a further $20 million general facility. In 2018, an additional $150 million bilateral credit facility, maturing in 2019, was available to CPC and $150 million had been drawn on the facility. Letters of credit of $189 million (2018 – $172 million) have been issued as described in note 35.

The Company has a bilateral unsecured $5 million demand facility available which is undrawn at December 31, 2019 (2018 – nil).

Under the terms of the unsecured credit facilities, the Company's subsidiaries may obtain advances by way of Canadian or U.S. prime loans, U.S. base rate loans, U.S. LIBOR loans and bankers' acceptances. Amounts drawn by way of prime or base rate loans each bear interest at the prevailing Canadian Prime, U.S. Prime, or U.S. base rate respectively, plus a spread ranging from nil to 1.25%, depending on the Company's credit rating. Amounts drawn by way of U.S. LIBOR loans or bankers' acceptances bear interest at the prevailing LIBOR rate or applicable bankers' acceptance rate plus a spread ranging from 1.00% to 2.25%, depending on the Company's credit rating.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

22. Reconciliation of movements of liabilities to cash flows arising from financing activities:

	2019	2018
Loans and borrowings[1]		
As at January 1	$ 2,647	$ 2,146
Changes from financing cash flows:		
Proceeds from issue of loans and borrowings[2]	900	705
Repayments	(633)	(195)
Deferred debt issue costs	(7)	(6)
Total changes from financing cash flows	260	504
Additions through business acquisitions (note 4)	590	-
Effect of changes in foreign exchange rates	(49)	63
Non-cash repayments on tax-equity financing	(57)	(80)
Implicit interest on tax-equity financing	20	16
Other non-cash items	2	(2)
Total other changes	506	(3)
As at December 31	$ 3,413	$ 2,647

[1] Includes deferred debt issue costs.

[2] Includes medium-term note issuances and private placement debt financing as at December 31, 2019 (2018 - includes the increase and use of additional committed credit facilities and the use of existing credit facilities).

	2019	2018
Lease liabilities[3]		
As at January 1	$ 18	$ 18
Changes from financing cash flows:		
Repayments	(12)	(1)
Interest on lease liabilities	5	-
Total changes from financing cash flows	(7)	(1)
IFRS transition (note 2(c))	96	-
Additions	4	-
Effects of changes in foreign exchange rates	-	1
Total other changes	100	1
As at December 31	$ 111	$ 18

[3] Includes the current portion disclosed within current deferred revenue and other liabilities.

23. Deferred revenue and other liabilities:

As at December 31	2019	2018 (note 2(c))
Deferred government grant revenue (note 15)	$ 341	$ 505
Other deferred revenue and liabilities	102	144
	443	649
Less current portions:		
Deferred government grant revenue	42	50
Lease liabilities	6	1
Other deferred revenue and liabilities	12	11
Total current deferred revenue and other liabilities	60	62
	$ 383	$ 587

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

24. Provisions:

As at December 31	2019	2018
Decommissioning	$ 356	$ 259
Employee benefits [1]	85	74
Other [2]	16	12
	457	345
Less: current portion	41	54
	$ 416	$ 291

[1] Included in the employee benefits provision is $24 million pertaining to the share-based payment obligations described in note 28, of which $24 million is vested at December 31, 2019 (2018 - $24 million total share-based payment obligation, $24 million vested).

[2] Included in other non-current provisions as at December 31, 2019 is $15 million (2018 – $9 million) pertaining to the Line Loss Rule Proceeding as described in note 34(e).

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2018	$ 228	$ 62	$ 12	$ 302
Additional liabilities incurred	12	31	-	43
Liabilities assumed in business combinations (note 4)	11	-	-	11
Liabilities settled	(3)	(19)	-	(22)
Amounts reversed unused	(2)	-	-	(2)
Foreign currency translation adjustments	5	-	-	5
Revisions to decommissioning costs (note 19)	3	-	-	3
Accretion (note 8)	5	-	-	5
As at December 31, 2018	$ 259	$ 74	$ 12	$ 345
Additional liabilities incurred [3]	36	43	6	85
Liabilities assumed in business combination (note 4)	40	-	-	40
G3 and K3 swap transaction (note 5)	1	-	-	1
Liabilities settled	(3)	(32)	-	(35)
Amounts reversed unused	(3)	-	(2)	(5)
Foreign currency translation adjustments	(4)	-	-	(4)
Revisions to decommissioning costs (note 19)	24	-	-	24
Accretion (note 8)	6	-	-	6
As at December 31, 2019	$ 356	$ 85	$ 16	$ 457

[3] Included in other additional liabilities incurred during the year ended December 31, 2019 is $6 million (2018 – nil) pertaining to the Line Loss Rule Proceeding as described in note 34(e).

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation facilities and the Genesee Coal Mine as it is obliged to remove the facilities at the end of their useful lives and restore the power facilities and mine sites to their original condition. Decommissioning provisions for the Coal Mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

At December 31, 2019, the Company's estimate of the undiscounted cash flow required to settle its decommissioning obligations is approximately $490 million (2018 - $421 million), calculated using an inflation rate of 2% (2018 – 2%). The expected timing for settlement of the obligations is between 2020 and 2055, which reflects ongoing reclamation of areas of the Genesee Coal Mine and the anticipated useful lives of the different power generation facilities.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

24. Provisions, continued:

Decommissioning provisions, continued

The majority of the payments to settle the obligations are expected to occur between 2031 and 2049 for the power generation facilities and between 2020 and 2028 for the mined, but un-reclaimed sections of the Genesee Coal Mine. Discount rates used to calculate the carrying amount of the obligations range from 1.58% to 2.39%. The actual timing and costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

25. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Unlimited preference shares, issuable in series:	
Series 1 and 2	5 million
Series 3 and 4	6 million
Series 5 and 6	8 million
Series 7 and 8	8 million
Series 9 and 10	6 million
Series 11 and 12	6 million
Special limited voting share	one

Issued and fully paid shares

	Common shares		Preference shares	
	Number of shares	Amount	Number of shares	Amount
As at January 1, 2018	104,314,093	$ 2,455	33,000,000	$ 807
Share purchase options exercised (note 28)	545,707	14	-	-
Common shares purchased [1]	(2,987,182)	(76)	-	-
As at December 31, 2018	101,872,618	$ 2,393	33,000,000	$ 807
Shares issued	4,945,000	150	6,000,000	150
Share issue costs	-	(7)	-	(5)
Deferred taxes on share issue costs (note 16)	-	1	-	1
Share purchase options exercised (note 28)	1,029,332	25	-	-
Common shares purchased [1]	(2,465,164)	(74)	-	-
As at December 31, 2019	105,381,786	$ 2,488	39,000,000	$ 953

[1] Common shares were purchased and canceled at an average exercise price of $29.85 per share for the year ended December 31, 2019 (year ended December 31, 2018 – $25.28 per share) under the Company's Toronto Stock Exchange approved normal course issuer bid.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

25. Share capital, continued:

Issued and fully paid shares, continued

On May 8, 2019, the Company completed a public offering of 4,945,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $30.30 per Subscription Receipt, for total gross proceeds of $150 million less issue costs of $7 million (inclusive of the full exercise of a 645,000 over-allotment option). On June 4, 2019, upon closing of the Goreway acquisition, each Subscription Receipt was converted for one common share of the Company.

On May 16, 2019, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series 11 (Series 11 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $5 million. The Series 11 Shares are redeemable by Capital Power, at its option on June 30, 2024 and every five years thereafter at a value of $25.00 per share.

The Company's shares are subject to a Shareholder Rights Plan (Rights Plan). The objective of the Rights Plan is to ensure, to the extent possible, the fair treatment of all shareholders in connection with any take-over bid for the securities of the Company, and to provide the Board with sufficient time to evaluate unsolicited take-over bids and to explore and develop alternatives to maximize shareholder value. The Rights Plan will continue in force until the end of the annual meeting of shareholders in 2022, at which time the Company expects to extend the Rights Plan for an additional 3 years, subject to Board of Directors and shareholder approval and subject to any changes in applicable securities law requirements.

Cumulative rate reset preference shares

Preferred shares	Dividend per share per annum [2]	Dividend rate reset	Redemption terms	Conversion terms [3]
Series 1	$0.765	Dividend rate was reset from $1.150 per annum to $0.765 per annum effective December 31, 2015 for the March 31, 2016 dividend payment and will be reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%.	Series 1 shares are redeemable by Capital Power, at its option, on December 31, 2020 and on December 31 of every fifth year thereafter.	Right to convert all or any part of shares into Cumulative Floating Rate Preference Shares, Series 2 (Series 2 Shares), subject to certain conditions, on December 31, 2020 and every five years thereafter.
Series 3	$1.363	Dividend rate was reset from $1.150 per annum to $1.363 per annum effective December 31, 2018 for the March 31, 2019 dividend payment and will be reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.23%.	Series 3 shares are redeemable by Capital Power, at its option, on December 31, 2023 and on December 31 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 4 (Series 4 Shares), subject to certain conditions, on December 31, 2023 and every five years thereafter.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

25. Share capital, continued:

Cumulative rate reset preference shares, continued

Preferred shares	Dividend per share per annum [2]	Dividend rate reset	Redemption terms	Conversion terms [3]
Series 5	$1.310	Dividend rate was reset from $1.125 per annum to $1.310 per annum effective June 30, 2018 for the September 30, 2018 dividend payment and will be reset every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.15%.	Series 5 shares are redeemable by Capital Power, at its option, on June 30, 2023 and on June 30 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 6 (Series 6 Shares) subject to certain conditions, on June 30, 2023 and every five years thereafter.
Series 7	$1.500	Dividend rate will be reset on December 31, 2021 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 5.26%, provided that, in any event, such rate shall not be less than 6.00%.	Series 7 Shares are redeemable by Capital Power, at its option, on December 31, 2021 and December 31 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Minimum Floating Rate Preference Shares, Series 8 (Series 8 Shares), subject to certain conditions, on December 31, 2021 and every five years thereafter.
Series 9	$1.438	Dividend rate will be reset on September 30, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.12%, provided that, in any event, such rate shall not be less than 5.75%.	Series 9 Shares are redeemable by Capital Power, at its option, on September 30, 2022 and on September 30 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Minimum Floating Rate Preference Shares, Series 10 (Series 10 Shares), subject to certain conditions, on September 30, 2022 and every five years thereafter.
Series 11	$1.438	Dividend rate will be reset on June 30, 2024 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.15%, provided that, in any event, such rate shall not be less than 5.75%.	Series 11 Shares are redeemable by Capital Power, at its option, on June 30, 2024 and on June 30 of every fifth year thereafter.	Right to convert all or any part of their shares into Cumulative Minimum Floating Rate Preference Shares, Series 12 (Series 12 Shares), subject to certain conditions, on June 30, 2024 and every five years thereafter.

[2] Holders of Series 1, Series 3, Series 5, Series 7, Series 9 and Series 11 shares will be entitled to receive fixed cumulative quarterly dividends that yield 3.06%, 5.45%, 5.24%, 6.00%, 5.75% and 5.75% respectively, per annum payable on the last business day of March, June, September, and December of each year, as and when declared by the Board of Directors of Capital Power.

[3] Holders of Series 2, Series 4, Series 6, Series 8, Series 10 and Series 12 shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, 3.23%, 3.15%, 5.26%, 4.12% and 4.15% respectively, as and when declared by the Board of Directors of Capital Power.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

25. Share capital, continued:

Common and preferred share dividends

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2019 and 2018 are summarized as follows:

	Dividends declared				Dividends paid			
	2019		2018		2019		2018	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common [4]	$ 1.8550	$ 195	$ 1.7300	$ 178	$ 1.8225	$ 190	$ 1.7000	$ 176
Preference:								
Series 1	0.7650	4	0.7650	4	0.7650	4	0.7650	4
Series 3	1.3633	8	1.1500	7	1.3633	8	1.1500	7
Series 5	1.3095	10	1.2173	10	1.3095	10	1.2173	10
Series 7	1.5000	12	1.5000	12	1.5000	12	1.5000	12
Series 9	1.4375	9	1.4375	8	1.4375	9	1.4375	8
Series 11	0.8960	5	-	-	0.8960	5	-	-

[4] On July 26, 2019, the Company's Board of Directors approved an increase of 7.3% in the annual dividend to $1.92 per common share effective for the third quarter of 2019.

26. Other cash items and change in non-cash operating working capital:

Other cash items

Year ended December 31	2019	2018
Realized losses on settlement of interest rate derivatives	$ (30)	$ -
Miscellaneous financing fees paid	(6)	(6)
Reclamation costs	(3)	(3)
Income taxes paid	(11)	(2)
Other	(17)	(11)
	$ (67)	$ (22)

Change in non-cash operating working capital

Year ended December 31	2019	2018
Trade and other receivables	$ 38	$ (78)
Inventories	11	(37)
Trade and other payables	20	66
Deferred revenue and other liabilities	(1)	(1)
Provisions	1	7
	$ 69	$ (43)

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

27. Related party balances and transactions:

Nature of transactions

As described in note 33, the Company is party to a number of joint arrangements, primarily for the construction and operation of power generating facilities. The joint arrangements provide energy to the Company and the Company provides management and operation services to the joint arrangements. Transactions with joint arrangements are eliminated to the extent of the Company's interest in the joint arrangement. Genesee 3 and Keephills 3 were both considered joint arrangements until close of the swap transaction during the fourth quarter of 2019 (note 5), at which time the ongoing activities of Genesee 3 will no longer include related party transactions.

Compensation of key management personnel

Year ended December 31	2019	2018
Short-term employee benefits	$ 6	$ 6
Share-based payments	6	5
	$ 12	$ 11

Key management personnel include certain executive officers of the Company in addition to the directors of the Company.

28. Share-based payments:

Share purchase options

Under the Company's long-term incentive plan, the Company provides share purchase options to certain employees to purchase common shares, provided that the number of shares reserved for issuance will not exceed 10% of the common shares to be outstanding at closing and that the aggregate number of shares issued by the Company under this plan will not exceed 9,194,506 common shares.

In March 2019, the Company granted 639,265 share purchase options with one third vesting on March 7 of each of 2020, 2021 and 2022. The fair values of these options at grant date were $2.50, $2.51 and $2.51 per option for the 2020, 2021 and 2022 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $30.78 per share.

In March 2018, the Company granted 719,050 share purchase options with one third vesting on March 7 of each of 2019, 2020 and 2021. The fair values of these options at grant date were $1.83, $1.88 and $1.91 per option for the 2019, 2020 and 2021 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $24.47 per share.

The following assumptions were used in estimating the fair value of the granted share purchase options:

	Share purchase options issued in:	
	2019	2018
Share price at grant date	$ 30.78	$ 24.47
Expected volatility [1]	16.90%	17.30%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	5.815%	6.600%
Risk-free interest rate [3]	1.88%	1.84%
Exercise price	$ 30.78	$ 24.47
Expiry date	March 7, 2026	March 7, 2025

[1] Volatility was estimated based on the historical volatility in the Company's share prices.

[2] Represents the average expected life of the three tranches for each grant date.

[3] Based on the Government of Canada zero-coupon yield curve. Represents the average risk-free rate of the three tranches for each grant date.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Share-based payments, continued:

Share purchase options, continued

The following illustrates share purchase options activity during the years ended December 31, 2019 and 2018:

	2019		2018	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	3,577,660	$ 22.93	3,957,502	$ 22.94
Granted	639,265	30.78	719,050	24.47
Exercised [4]	(1,029,332)	22.43	(545,707)	23.25
Forfeited	(9,406)	24.03	(70,711)	23.58
Expired	(1,197)	30.78	(482,474)	24.83
Options outstanding, as at December 31	3,176,990	$ 24.66	3,577,660	$ 22.93
Vested options outstanding, as at December 31	1,867,357	$ 22.52	2,164,726	$ 22.68

[4] The weighted average share price at the date of exercise was $30.65 (2018 - $27.09).

During the year ended December 31, 2019, the Company recorded compensation expense of $2 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2018 – $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2019 is 3.98 years (2018 – 3.78 years). The exercise prices of share purchase options outstanding as at December 31, 2019 range from $17.33 to $30.78 (2018 - $17.33 to $25.53).

Performance share units

Capital Power grants PSUs to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount based on the prevailing market price of such number of common shares on the release date. PSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. Participants receive payments based on the number of units vested including dividend equivalents with an ending value based on the prevailing market price at the time of payment. PSUs will be paid in cash based on the Company's share performance relative to a group of peer organizations ranging from 0% to 200% times the market price of the PSU at the release date.

	2019	2018
PSUs outstanding, as at January 1	380,862	355,220
Granted [5]	100,695	113,758
Released [6]	(298,100)	(88,054)
Dividends reinvested	157,905	28,657
Forfeited	(2,817)	(28,719)
PSUs outstanding, as at December 31	338,545	380,862

[5] The fair value of the PSUs at the grant date was $28.66 (2018 - $23.34).

[6] The weighted average share price at the date of release was $27.31 (2018 - $24.26).

During the year ended December 31, 2019, the Company recorded a compensation expense of $7 million (2018 – $8 million) related to the outstanding PSUs in staff costs and employee benefits expense.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

28. Share-based payments, continued:

Restricted share units

Capital Power grants RSUs to certain employees, which entitle those employees to receive payments based on an equivalent number of common shares at a specified release date for an amount equal to the market price of such number of common shares on the release date. RSUs are paid out three years from the grant date and vest as service is rendered over that three-year period. RSUs will be paid out to participants in cash based on the number of units vested including dividend equivalents with an ending value equal to the prevailing market price of Capital Power common shares at the time of payment.

	2019	2018
RSUs outstanding, as at January 1	309,080	310,212
Granted [7]	83,538	96,713
Released [8]	(131,639)	(93,187)
Dividends reinvested	16,899	20,785
Forfeited	(3,559)	(25,443)
RSUs outstanding, as at December 31	274,319	309,080

[7] The fair value of the RSUs at the grant date was $28.66 (2018 – $23.34).

[8] The weighted average share price at the date of release was $27.34 (2018 – $24.26).

During the year ended December 31, 2019, the Company recorded a compensation expense of $4 million (2018 – $3 million) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred share units

The Company has approved a DSU Plan pursuant to which non-employee directors of the Company may receive their annual equity retainer in the form of DSUs. Directors are entitled to elect to receive their annual retainer, committee retainer, and/or committee chair retainer in full or partial DSUs. Directors will receive additional DSUs in respect of dividends payable on common shares of the Company based on the value of a DSU at that time. DSUs vest immediately and are redeemed for cash six months after a director's resignation from the Board of Directors, using the average closing price of the Company's common shares on the Toronto Stock Exchange for the five trading days immediately before the redemption date. During the year ended December 31, 2019, the Company recorded a compensation expense of $3 million (2018 – $2 million) related to the outstanding DSUs in staff costs and employee benefits expense.

29. Financial instruments:

Fair values

The Company classifies and measures its cash and cash equivalents, trade and other receivables and trade and other payables at amortized cost and their fair values are not materially different from their carrying amounts due to their short-term nature.

Details of the Company's derivative instruments are described in note 14.

The classification, carrying amount and fair value of the Company's other financial instruments are summarized as follows:

		December 31, 2019		December 31, 2018	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets [1]					
Government grant receivable (note 15)	Level 2	476	435	511	505
Financial liabilities [1]					
Loans and borrowings (note 21)	Level 2	3,413	3,505	2,647	2,645

[1] Includes current portion

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

29. Financial instruments, continued:

Fair value hierarchy

The table below presents the Company's financial instruments measured at fair value on a recurring basis in the consolidated statements of financial position, classified using the fair value hierarchy described in note 3.

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 193	$ 41	$ 234
Derivative financial instruments liabilities	-	(298)	-	(298)

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 143	$ 16	$ 159
Derivative financial instruments liabilities	-	(160)	(44)	(204)

Valuation techniques used in determination of fair values within Level 3

The Company 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, their fair values are derived using forecasts based on internal modelling and as a result, are classified within Level 3 of the hierarchy.

The Company has a fixed price contract to swap the market revenue of its Bloom Wind generation for a fixed annual payment for a 10-year term that expires in 2027. Commencing in 2019, forward market prices are available for the remaining period of this contract, however anticipated generation continues to be forecasted based on internal modelling. Accordingly, this financial instrument is classified as Level 3.

In addition, as at December 31, 2019 and December 31, 2018, the Company holds contracts for the sale of RECs for which pricing beyond two years is not readily observable and the contracts are therefore classified in Level 3 of the hierarchy.

The fair values of the Company's commodity derivatives included within Level 3 are determined by applying a mark-to-forecast model. The table below presents ranges for the Company's Level 3 inputs:

As at December 31	2019	2018
REC pricing (per certificate) – Thermal	$1.05	$1.09
REC pricing (per certificate) – Solar	$210.94 to $405.33	$221.55 to $395.64
Power pricing (per MWh) – Wind	$16.88 to $49.14	$15.48 to $70.68
Monthly generation (MWh) – Bloom Wind	54,426 to 72,000	54,426 to 72,000

Valuation process applied to Level 3

The valuation models used to calculate the fair value of the derivative financial instruments assets and liabilities within Level 3 are prepared by appropriate internal subject matter experts and reviewed by the Company's commodity risk group and by management. The valuation technique and the associated inputs are assessed on a regular basis for ongoing reasonability.

The table below presents the impact to fair value of Level 3 derivative instruments based on reasonably possible alternative assumptions:

As at December 31	2019	2018
REC pricing – Thermal [2]	$ -	$ -
REC pricing – Solar [2]	-	-
Power pricing – Wind [2]	10	17
Generation – Bloom Wind [3]	11	14

[2] Reflects the increase or decrease to fair value calculated using a $1 per unit decrease or increase in the input.

[3] Reflects the increase or decrease to fair value calculated using a 10% decrease or increase in the input.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

29. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances

The Company classifies financial instruments in Level 3 of the fair value hierarchy when there is reliance on at least one significant unobservable input to the valuation model used to determine fair value. In addition to these unobservable inputs, the valuation model for Level 3 instruments also relies on a number of inputs that are observable either directly or indirectly. Accordingly, the unrealized gains and losses shown below include changes in the fair value related to both observable and unobservable inputs. The following table summarizes the changes in the fair value of financial instruments classified in Level 3:

	2019	2018
As at January 1 [4]	$ (28)	$ 30
Unrealized and realized gains (losses) included in net income [5]	69	(55)
Transfers [6]	-	(5)
Foreign exchange gain	-	2
As at end of period	$ 41	$ (28)
Total unrealized and realized gains (losses) for the period included in net income [5]	$ 69	$ (55)

[4] The fair value of derivative instruments assets and liabilities are presented on a net basis.

[5] Recorded in revenues.

[6] Relates to transfers from Level 3 to Level 2 when pricing inputs became readily observable.

All instruments classified as Level 3 are derivative type instruments. Gains and losses associated with Level 3 balances may not necessarily reflect the underlying exposures of the Company. As a result, unrealized gains and losses from Level 3 financial instruments are often offset by unrealized gains and losses on financial instruments that are classified in Levels 1 or 2.

Financial assets

The fair value of the Company's government grant receivable held at amortized cost is estimated by discounting its expected future cash flows at current market interest rates for comparable instruments with similar terms, plus an estimated credit spread based on the counterparty credit risk as at December 31, 2019 and 2018.

Financial liabilities

The fair values of the Company's loans and borrowings are based on determining a current yield for the Company's loans and borrowings as at December 31, 2019 and 2018. This yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada and U.S. Government bonds that have similar maturities to the Company's loans and borrowings. The estimated credit spread is based on the Company's indicative spread as published by independent financial institutions.

Offsetting of financial assets and liabilities

The Company's commodity trading transactions are typically transacted on an exchange or under International Swap Dealers Association Master Agreements or similar master agreements. In general, under the Company's trading agreements the amounts owed by each counterparty that are due on a single day in respect of all transactions outstanding in the same currency under the agreement are aggregated into a single net amount being payable by one party to the other. Such amounts meet the criteria for offsetting and are presented as such on the Company's statements of financial position. In certain circumstances, including when a credit event such as a default occurs, generally all outstanding transactions under the agreement are terminated, the termination value is assessed and only a single net amount is payable by one party to the other in settlement of all transactions. Amounts that may only be offset in these circumstances do not meet the criteria for offsetting on the Company's statements of financial position.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

29. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

The Company also has an agreement in place with one of its energy trading counterparties that conveys to the counterparty the right to set-off amounts receivable and amounts payable between the Company and the counterparty in certain circumstances, including when a credit event such as a default occurs on the part of the Company. Such amounts do not meet the criteria for offsetting on the Company's statements of financial position. The Company issues and accepts collateral in the form of cash and letters of credit in respect of its commodity trading transactions. Such collateral is generally subject to standard industry terms. The terms generally also give each counterparty the right to terminate the related transactions upon the other counterparty's failure to post collateral.

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements

				Related amounts not offset in the statement of financial position		
Types of financial assets	Gross amounts of recognized financial assets	Gross amounts of recognized financial liabilities offset in the statement of financial position	Net amounts of financial assets presented in the statement of financial position [7]	Financial instruments	Collateral received [8]	Net amount
As at December 31, 2019						
Commodity trading assets	$ 321	$ (22)	$ 299	$ (99)	$ (2)	$ 198
As at December 31, 2018						
Commodity trading assets	$ 213	$ (17)	$ 196	$ (48)	$ (7)	$ 141

[7] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $81 million, non-current derivative instruments assets of $151 million and trade and other receivables of $67 million (December 31, 2018: current derivative instruments assets of $65 million, non-current derivative instruments assets of $82 million and trade and other receivables of $49 million).

[8] Collateral received relating to the net financial assets disclosed above is in the form of letters of credit received from the Company's counterparties.

Financial liabilities subject to offsetting, enforceable master netting arrangements or similar arrangements

				Related amounts not offset in the statement of financial position		
Types of financial liabilities	Gross amounts of recognized financial liabilities	Gross amounts of recognized financial assets offset in the statement of financial position	Net amounts of financial liabilities presented in the statement of financial position [9]	Financial instruments	Collateral pledged	Net amount
As at December 31, 2019						
Commodity trading liabilities	$ 272	$ (22)	$ 250	$ (113)	$ (27)	$ 110
As at December 31, 2018						
Commodity trading liabilities	$ 250	$ (17)	$ 233	$ (62)	$ (28)	$ 143

[9] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $97 million, non-current derivative instruments liabilities of $118 million and trade and other payables of $35 million (December 31, 2018: current derivative instruments liabilities of $82 million, non-current derivative instruments liabilities of $114 million and trade and other payables of $37 million).

30. Risk management

Risk management overview

The Company is exposed to a number of financial risks, arising from business activities and its use of financial instruments, including market risk, credit risk and liquidity risk. The Company's overall risk management process is designed to identify, manage and mitigate business risk which includes, among other risks, financial risk. Risk management is overseen by the Company's executive team according to objectives, targets, and policies approved by the Capital Power Board of Directors. The executive team is comprised of the most senior management group within the Company.

Risk management strategies, policies, and limits are designed to help ensure the risk exposures are managed within the Company's business objectives and risk tolerance. The Company's financial risk management objective is to protect and limit the volatility in income and cash flow.

Commodity price risk management and the associated credit risk management are carried out in accordance with the respective commodity, credit, and financial exposures risk management policies, as approved by the executive team and the Board of Directors. Financial risk management, including foreign exchange risk, interest rate risk, and liquidity risk, is carried out by a centralized Treasury function, also in accordance with a financial risk management policy approved by the executive team and the Board of Directors. Capital Power's Audit Committee of the Board of Directors, in its oversight role, monitors the assessment of financial risk management controls and procedures to ensure compliance with applicable policies.

Market risk

Market risk is the risk of loss that results from changes in market factors such as commodity prices, foreign currency exchange rates, interest rates and equity prices. The level of market risk to which the Company is exposed at any point in time varies depending on market conditions, expectations of future price or market rate movements and the composition of the Company's financial assets and liabilities held, non-trading physical asset and contract portfolios, and trading portfolios.

To manage the exposure related to changes in market risk, the Company uses various risk management techniques including derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps (or contracts-for-differences), and option contracts. Such derivative instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency. Commodity risk exposures are monitored daily against approved risk limits, and control processes are in place to monitor that only authorized activities are undertaken.

The sensitivities provided in each of the following risk discussions disclose the effect of reasonably possible changes in relevant prices and rates on net income at the reporting date. The sensitivities are hypothetical and should not be considered to be predictive of future performance or indicative of income on these contracts. The Company's actual exposure to market risks is constantly changing as the Company's portfolio of debt, foreign currency and commodity contracts changes. Changes in fair values or cash flows based on market variable fluctuations cannot be extrapolated since the relationship between the change in the market variable and the change in fair value or cash flows may not be linear. In addition, the effect of a change in a particular market variable on fair values or cash flows is calculated without considering interrelationships between the various market rates or mitigating actions that would be taken by the Company.

30. Risk management, continued:

Market risk, continued

Commodity price risk

The Company is exposed to commodity price risk as part of its normal business operations, including energy procurement activities in Canada and the U.S. The Company's energy procurement activities consist of power generation, non-market traded and market traded electricity, natural gas and emission credits purchase and sales contracts, and derivative contracts. The Company is primarily exposed to changes in the prices of electricity and natural gas. The Company actively manages commodity price risk by optimizing its asset and contract portfolios utilizing the following methods:

- The Company reduces its exposure to the volatility of commodity prices related to electricity sales and natural gas purchases by entering into offsetting contracts such as contracts-for-differences and firm price physical contracts for periods of varying duration.
- The Company enters into fixed-price energy sales contracts and power purchase arrangements which limit the exposure to electricity prices. The Company has entered into long-term tolling arrangements whereby variable changes linked to the price of natural gas and coal are assumed by the counterparty.
- The Company enters into back-to-back electricity and natural gas physical and financial contracts to lock in a margin.

The Company also engages in taking market risk positions within authorized limits approved by Capital Power's executive team and Board of Directors. The trading portfolio includes electricity and natural gas physical and financial derivative contracts which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities.

The fair value of the Company's energy related derivatives as at December 31, 2019, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 14.

The Company employs a Value-at-Risk (VaR) methodology to manage risk exposures to commodity prices on a consolidated basis. VaR measures the estimated potential loss in a portfolio of positions associated with the movement of a commodity price for a specified time or holding period and a given confidence level. Capital Power's VaR for positions expected to settle in 2020, as at December 31, 2019, uses a statistical confidence interval of 99% over a ten-business day holding period. This measure reflects a 1% probability that, over the ten-day period commencing with the point in time that the VaR is measured, the fair value of the overall commodity portfolio could decrease by an amount in excess of the VaR amount. The VaR methodology is a statistically-defined, probability-based approach that takes into consideration market volatilities and risk diversification by recognizing offsetting positions and correlations between products and markets. This technique makes use of historical data and assesses the market risk arising from possible future changes in commodity prices over the holding period.

VaR should be interpreted in light of the limitations of the methodologies used. These limitations include the following:

- VaR calculated based on a holding period may not fully capture the market risk of positions that cannot be liquidated or hedged within the holding period.
- The Company computes VaR of the portfolios at the close of business and positions may change substantially during the course of the day.
- VaR, at a 99% confidence level, does not reflect the extent of potential losses beyond that percentile. Losses on the other 1% of occasions could be substantially greater than the estimated VaR.

30. Risk management, continued:

Market risk, continued

Commodity price risk, continued

These limitations and the nature of the VaR measurements mean that the Company can neither guarantee that losses will not exceed the VaR amounts or that losses in excess of the VaR amounts will not occur more frequently than 1% of the time. As VaR is not a perfect predictor of risk, the Company undertakes back testing and periodically calibrates the VaR calculation to a 99% confidence level.

The estimation of VaR takes into account positions from all wholly-owned subsidiaries and subsidiaries in which the Company has a controlling interest, and reflects the Company's aggregate commodity positions from its trading and asset portfolios. Capital Power's Board of Directors has approved the methodology for the ongoing determination of commodity risk limits, under their commodity risk management policy. Commodity risk is monitored on a daily basis and reported to the executive team on a monthly basis at a minimum and more frequently if exceptions and/or material changes are identified. The portfolios are stress tested regularly to observe the effects of plausible scenarios taking into account historical price movements and certain hypothetical extreme events. As at December 31, 2019, the VaR of the Company's commodity trading and assets portfolios for 2020 as a result of unfavourable market price changes is $12 million based on a 99% confidence level and a holding period of ten days.

Foreign exchange risk

The Company is exposed to foreign exchange risk on foreign currency denominated forecasted transactions, firm commitments, and monetary assets and liabilities denominated in a foreign currency and on its net investments in foreign operations. The Company's operations expose it to foreign exchange risk arising from transactions denominated in foreign currencies. The Company's foreign exchange risk arises primarily with respect to the U.S. dollar but it is potentially exposed to changes in other currencies if and when it transacts in other currencies. The risk is that the functional currency value of cash flows will vary as a result of the movements in exchange rates.

The Company's foreign exchange management policy is to limit economic and material transactional exposures arising from movements in the Canadian dollar relative to the U.S. dollar or other foreign currencies. The Company's exposure to foreign exchange risk arises from future anticipated cash flows from its U.S. operations, debt service obligations on U.S. dollar borrowings, and from certain capital expenditure commitments denominated in U.S. dollars or other foreign currencies. The Company co-ordinates and manages foreign exchange risk centrally, by identifying opportunities for naturally-occurring opposite movements and then dealing with any material residual foreign exchange risks; these are hereinafter referred to as being economically hedged. The Company may also use derivative instruments to manage foreign exchange risk. At December 31, 2019, the Company held no foreign exchange derivatives.

As at December 31, 2019, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would have increased or decreased net income attributable to shareholders by $1 million (2018 – decreased or increased by $10 million). There would be no impact to other comprehensive income.

This sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency to the functional currency of the Company and financial instruments denominated in the functional currency in which they are transacted and measured.

30. Risk management, continued:

Market risk, continued

Interest rate risk

The Company is exposed to changes in interest rates on its cash and cash equivalents, and floating rate current and non-current loans and borrowings. The Company is exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments. The Company uses floating rate funding for current borrowings and other liquidity requirements. In addition, the debt assumed as a part of the business acquisition described in note 4 is a floating-rate bank facility. As at December 31, 2019, the proportion of fixed rate loans and borrowings was approximately 74% of total loans and borrowings outstanding (2018 - 77%). The Company uses derivative instruments to manage interest rate risk. At December 31, 2019, the Company held interest rate derivatives as disclosed in notes 4 and 14 which effectively increased the proportion of fixed rate loans and borrowings to 88% as at December 31, 2019. Beyond the interest rate derivatives on the assumed debt described above, the Company holds interest rate derivatives which effectively fix the underlying Government of Canada rate portion of its floating-rate debt interest rate. This debt remains floating-rate debt as it is exposed to movements in the Company's interest rate spread and as such the economic proportion of fixed-rate debt at December 31, 2018 remained at 77%.

Assuming that the amount and mix of fixed and floating rate loans and borrowings and net loans and borrowings remains unchanged from that held as at December 31, 2019, a 100 basis point decrease or increase to interest rates would increase or decrease full year net income attributable to common shareholders by $3 million (2018 – $4 million) and would have no direct impact on other comprehensive income.

The effect on net income does not consider the effect of an overall change in economic activity that would accompany such an increase or decrease in interest rates.

Credit risk

Credit risk is the possible financial loss associated with the inability of counterparties to satisfy their contractual obligations to the Company. The Company's counterparty credit risk management policy is established by the executive team and approved by the Board of Directors. The associated procedures and practices are designed to manage the credit risks associated with the various business activities throughout the Company. Credit risk management procedures and practices generally include assessment of individual counterparty creditworthiness and establishment of exposure limits prior to entering into any agreements or transactions with the counterparty. Credit exposures and concentrations are subsequently monitored and are regularly reported to management on an ongoing basis. Counterparty creditworthiness also continues to be evaluated on an ongoing basis after transactions have been initiated.

Credit risk is managed and mitigated through a number of risk mitigation practices such as securing parent company guarantees to enhance counterparty credit quality, negotiating and obtaining security (such as cash, letters of credit or property) to offset potential losses, utilization of credit derivatives to reduce credit risk and margining to limit credit risk where applicable.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

30. Risk management, continued:

Credit risk, continued

Maximum credit risk exposure

The Company’s maximum credit exposure was represented by the following financial assets:

As at December 31	2019	2018 (note 2(c))
Cash and cash equivalents (note 11)	$ 248	$ 182
Trade and other receivables (note 12) [1]	334	438
Derivative financial instruments assets (note 14) [1]	234	159
Government grant receivable (note 15)	423	459
	$ 1,239	$ 1,238

[1] The Company’s maximum credit exposures related to trade and other receivables and derivative financial instruments assets by major credit concentration are comprised of maximum exposures of $258 million (2018 - $186 million) for wholesale counterparties and $310 million (2018 - $411 million) for generation and other counterparties as at December 31, 2019.

The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. As at December 31, 2019, the Company also held other forms of credit enhancement in the forms of letters of credit of $29 million (2018 - $74 million), parental guarantees of $1,967 million (2018 - $1,772 million) and property registrations $46 million (2018 - $53 million) related to the financial assets noted above. As at December 31, 2019 and 2018, the Company also held parental guarantees which do not have a defined amount or limit, but which provide full support on any outstanding positions related to counterparty performance for power purchase arrangements and certain other operating and construction contracts.

Credit quality and concentrations

The Company is exposed to credit risk on outstanding trade and other receivables associated with its generation and optimization activities including power purchase arrangements, agreements with independent system operators, power and steam sales contracts, energy supply agreements with government sponsored entities, wholesale customers, and trading counterparties. The Company is also exposed to credit risk related to its cash and cash equivalents (which include short-term investments), financial and non-financial derivative instruments assets and long-term financing arrangements.

The credit quality and concentrations of the Company’s trade and other receivables and other financial assets, by major credit concentrations are the following:

Cash and cash equivalents

The Company has significant credit and performance exposures to financial institutions as they provide committed credit lines and cash deposit facilities, are the primary counterparty of the Company's interest rate and foreign exchange derivative instruments, and facilitate letters of credit to mitigate the Company's exposure to certain counterparties. The Company manages its credit risk on cash and cash equivalents, and short-term investments by dealing with investment grade rated banks and financial institutions and reviewing each investment vehicle to ensure the underlying credit risk is known.

Trade and other receivables and financial derivative instruments

Trade and other receivables are substantially made up of receivables related to the generation and sale of electricity to customers including industrial and commercial customers, independent system operators from various regions and government-owned or sponsored entities and the settlement of financial derivative instruments related to merchant price risk mitigation and trading activities. The Company manages its credit risk on these financial assets through its credit adjudication process, dealing with creditworthy counterparties and utilizing the credit risk mitigation practices noted above.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

30. Risk management, continued:

Credit risk, continued

Generation credit risk

Credit risk exposure from PPAs, agreements with independent system operators, power and steam sales contracts, and certain energy supply agreements is predominantly restricted to trade and other receivables and contract default. In certain cases, the Company relies on a single or small number of customers to purchase all or a significant portion of a facility's output. The failure of any one of these counterparties to fulfill its contractual obligations could negatively impact the Company's financial results. Financial loss resulting from events of default by counterparties in certain PPAs and steam purchase arrangements may not be recovered since the contracts may not be replaceable on similar terms under current market conditions. Consequently, the Company's financial performance depends on the continued performance by customers and suppliers of their obligations under these long-term agreements. Credit risk exposure is mitigated by dealing with creditworthy counterparties that are determined to be investment grade based on the Company's internally assigned ratings or employing mitigation strategies as noted above, netting amounts by legally enforceable set-off rights, and, when appropriate, taking security from the counterparty. Credit risk with counterparties in this asset class that are government-owned or sponsored entities and regulated public utility distributors is generally considered low.

The Company is party to a contract whereby it sells renewable energy credits to Pacific Gas and Electric Company (PG&E) which, in January 2019, filed for bankruptcy and subsequently had its credit rating downgraded to "D", representing default. PG&E faces political and regulatory pressure and needs the support of multiple stakeholders before they will be able to exit from bankruptcy. At this time, PG&E has continued to fulfill their obligations to the Company under the contract. As PG&E's bankruptcy proceeds, the Company will continue to monitor the situation. If at some point, PG&E is no longer able to fulfill their obligations under the contract, the Company would have to pursue replacement contracts which may not be replaceable on similar terms to the existing contract.

Wholesale and merchant credit risk

Credit risk exposure for wholesale and merchant trading counterparties is measured by calculating the costs (or proceeds) of replacing the commodity position (physical and derivative contracts), adjusting for settlement amounts due to or due from the counterparty and, if permitted, netting amounts by legally enforceable set-off rights. Financial loss on wholesale contracts could include, but is not limited to, the cost of replacing the obligation, amounts owing from the counterparty or any loss incurred on liability settlements. Wholesale and merchant credit risk exposure is mitigated by trading with investment grade and creditworthy counterparties, portfolio diversification, monitoring of credit exposure limits, margining to reduce energy trading risks, obtaining parent company guarantees, and when appropriate, taking security from counterparties.

Trade and other receivables and allowance for doubtful accounts

Trade and other receivables consist primarily of amounts due from customers including commercial and industrial customers, independent system operators from various regions, government-owned or sponsored entities, and other counterparties. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit if deemed appropriate. The Company also has credit exposures to large suppliers of electricity and natural gas. The Company mitigates these exposures by dealing with creditworthy counterparties and, when appropriate, taking appropriate security from the supplier.

The aging of trade and other receivables as at December 31, 2019 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [2]	$ 332	$ -	$ 332
Outstanding greater than 90 days	2	-	2
	$ 334	$ -	$ 334

[2] Current amounts represent trade and other receivables outstanding zero to 30 days. Amounts outstanding more than 30 days are considered past due.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

30. Risk management, continued:

Credit risk, continued

Trade and other receivables and allowance for doubtful accounts, continued

As at December 31, 2019 and 2018, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

As at December 31, 2019 and 2018, there were no expected credit losses associated with trade and other receivables from treasury, trading and energy procurement counterparties as all balances were considered to be fully collectible.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's liquidity is managed centrally by the Treasury function. The Company manages liquidity risk through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and also by matching the maturity profiles of financial assets and liabilities to identify financing requirements. The financing requirements are addressed through a combination of committed and demand revolving credit facilities, financings in public and private debt markets and equity offerings by the Company or its CPLP subsidiary.

As at December 31, 2019, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $897 million (2018 - $490 million), of which $631 million is committed to 2024 (2018 - $437 million committed to 2023).

In addition to the facilities noted above, the Company has a shelf prospectus under which it may raise funds in the form of debt or equity. As at December 31, 2019, Capital Power has a Canadian shelf prospectus, which expires in June 2020, under which it may raise up to $3 billion collectively in common shares of the Company, preference shares of the Company, subscription receipts exchangeable for common shares and/or other securities of the Company, and debt securities of the Company.

The following are the undiscounted cash flow requirements and contractual maturities of the Company's financial liabilities, including interest payments, and where applicable, net of financial assets that generate cash inflows to meet cash outflows on financial liabilities as at December 31, 2019:

	Due within 1 year	Due between 1 and 2 years	2 and 3 years	3 and 4 years	4 and 5 years	Due after more than 5 years	Total contractual cash flows
Non-derivative financial liabilities:							
Loans and borrowings [3,4] (note 21)	$ 824	$ 315	$ 17	$ 17	$ 787	$ 1,246	$ 3,206
Interest payments on loans and borrowings	134	101	92	91	85	213	716
Trade and other payables [5] (note 20)	282	-	-	-	-	-	282
Lease liabilities	10	9	9	9	9	113	159
Derivative financial liabilities (net of financial assets):							
Commodity and other derivatives	-	-	-	3	2	8	13
Total	$ 1,250	$ 425	$ 118	$ 120	$ 883	$ 1,580	$ 4,376

[3] Repayments of loans and borrowings exclude fair value differentials of $19 million related to debt assumed on previous asset acquisitions and $213 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

[4] Due within 1 year includes Goreway non-recourse financing of $559 million that was re-financed subsequent to year end and due to mature in January 2027 (see note 4).

[5] Excluding accrued interest on loans and borrowings of $19 million.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

31. Capital management:

The Company's primary objectives when managing capital are to safeguard the Company's ability to continue as a going concern, pay regular dividends to its shareholders, maintain a suitable credit rating, and to facilitate the acquisition or development of projects in Canada and the U.S. consistent with the growth strategy of the Company. The Company manages its capital structure in a manner consistent with the risk characteristics of the underlying assets.

The Company manages capital through regular monitoring of cash and currency requirements by preparing short-term and long-term cash flow forecasts and reviewing monthly financial results. The Company matches the maturity profiles of financial assets and liabilities to identify financing requirements to help ensure an adequate amount of liquidity.

The Company considers its capital structure to consist of loans and borrowings net of cash and cash equivalents and equity (which includes non-controlling interests).

The following table represents the total capital of the Company:

As at December 31	2019	2018 (note 2(c))
Loans and borrowings (note 21)	$ 3,413	$ 2,647
Lease liabilities [1] (note 17)	111	18
Cash and cash equivalents (note 11)	(248)	(182)
Net debt	3,276	2,483
Share capital (note 25)	3,441	3,200
Deficit and other reserves	(377)	(190)
Non-controlling interests (note 32)	37	43
Total equity	3,101	3,053
	$ 6,377	$ 5,536

[1] Includes the current portion disclosed within deferred revenue and other liabilities.

Capital Power has senior unsecured long-term debt ratings of BBB- (stable outlook) and BBB (low) assigned by Standard & Poor's (S&P) and DBRS Limited (DBRS) respectively. Capital Power has preferred share ratings of P-3 and Pfd-3 (low) assigned by S&P and DBRS, respectively.

Capital Power has the following externally imposed requirements on its capital as a result of its credit facilities and certain debt covenants, as defined in the respective agreements:

- Maintenance of modified consolidated net tangible assets to consolidated net tangible assets ratio, as defined in the debt agreements, of not less than 0.75 to 1.0;
- Maintenance of consolidated senior debt to consolidated capitalization ratio, as defined in the debt agreements, of not more than 0.65 to 1.0;
- Limitation on debt issued by subsidiaries; and
- In the event that Capital Power is assigned a rating of less than BBB- from S&P and BBB (Low) from DBRS (in each case with a stable outlook), Capital Power would also be required to maintain a ratio of consolidated earnings before interest, income taxes, depreciation and amortization to consolidated interest expense, as defined in the debt agreements, of not less than 2.5 to 1.0.

For the years ended December 31, 2019 and 2018, Capital Power complied with all externally imposed capital restrictions.

To manage or adjust its capital structure, the Company can issue new loans and borrowings, issue common or preferred shares, buy back common shares, redeem preferred shares, repay existing loans and borrowings or adjust dividends paid to its shareholders.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

32. Investments in subsidiaries that have non-controlling interests:

Set out below is the Company's principal subsidiary that has a non-controlling interest (NCI) at December 31, 2019:

	Place of business	Percentage of ownership interest held by the Company	Percentage of ownership interest held by the NCI	Principal activities
Genesee Coal Mine Assets (Coal Mine)	Canada	50%	50%	Coal production for use in power generation

The Company holds a 50% interest in the Coal Mine while the other 50% is held by an external party. The decisions about the relevant activities of the Coal Mine are made based on a majority vote by the Management Committee. The Management Committee is comprised of three members appointed by each of the Company and the external party. Based on the terms of the agreement surrounding the operations of the Coal Mine, it is noted that under the circumstance where the two parties are in a deadlock with respect to a decision that would affect the relevant activities of the Coal Mine, Capital Power holds the deciding vote. Given Capital Power's voting rights, Capital Power has control to affect the variability in its returns. Based on an assessment of the relationship between Capital Power and the Coal Mine, Capital Power controls the Coal Mine and therefore the Coal Mine is treated as a subsidiary of Capital Power.

There are no significant restrictions on access to the subsidiary's assets.

The summarized financial information of the Coal Mine is as follows:

Consolidated statements of financial position and loss and other comprehensive loss	2019	2018
Non-current assets	$ 70	$ 82
Net loss and comprehensive loss attributable to partners	$ (13)	$ (15)

Consolidated statements of cash flows	2019	2018
Net cash flows used in investing activities	$ (10)	$ (14)
Net cash flows from financing activities	10	14
Net increase (decrease) in cash and cash equivalents	-	-
Cash and cash equivalents at beginning of year	-	-
Cash and cash equivalents at end of year	$ -	$ -

Non-controlling interests reflected on the consolidated statement of financial position are comprised of:

Year ended December 31	2019	2018
Non-controlling interest in the Coal Mine, beginning of year	$ 41	$ 48
Net loss attributable to non-controlling interest	(6)	(7)
Non-controlling interest in the Coal Mine, end of year	$ 35	$ 41
Non-controlling interest in Macho Springs [1]	2	2
Total non-controlling interests, end of year	$ 37	$ 43

[1] Effective for the fourth quarter of 2018, the Company's Macho Springs subsidiary, which is financed under a tax equity financing structure, reached its flip date. As a result, the remaining tax-equity financing balance was reclassified from loans and borrowings and into non-controlling interests.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

33. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2019:

	Place of business	% of ownership interest
Joffre Cogeneration Project (Joffre) [1]	Canada	40%
Shepard Energy Centre (Shepard) [2]	Canada	50%
Genesee 4 and 5 [3]	Canada	50%

[1] Joffre is a 480 MW gas-fired combined cycle cogeneration facility in which Capital Power holds a 40% interest with external parties holding 40% and 20% interests, respectively. The Company's investment in the Joffre joint arrangement, which is incorporated as a separate legal entity, has been determined to be a joint operation since the contractual arrangements governing the joint arrangement indicate that the parties to the arrangement are entitled to the assets of the joint arrangement and are exposed to the liabilities of the joint arrangement in proportion to their ownership interest.

[2] Shepard is an 860 MW gas-fired generating facility in which Capital Power holds a 50% interest while the other 50% is held by an external party, with the external party responsible for management and operations. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[3] Genesee 4 and 5 is a 1,060 MW gas-fired generating project in which Capital Power holds a 50% interest while the other 50% is held by an external party, with Capital Power responsible for construction and operations of the project. The Company's commitments associated with Genesee 4 and 5 are described in note 34(a).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 21 pertaining to the charges on the Joffre assets.

Joint ventures

York Energy Centre L.P. (York Energy) is a 400 MW natural gas-fired power generating facility, located in Ontario, Canada, in which Capital Power holds a 50% interest while the other 50% is held by an external party. The Company's investment in York Energy, which consists of separate legal entities, has been determined to be a joint venture and is accounted for under the equity method. The Company's obligations are limited to their capital contributions to the joint arrangement, and the Company's receipts of the economic benefits of the joint arrangement are limited to the quarterly distributions. As a result, there is no indication that the Company has rights to the assets or obligations for the liabilities of the joint arrangement and the investment has been classified as a joint venture.

Disposal of interest in joint venture

K2 Wind is a 270 MW wind facility in which Capital Power held a one-third ownership interest with two external parties. The Company's investment in K2 Wind was classified as a joint venture and accounted for under the equity method.

On December 31, 2018 the Company completed the sale of its one-third ownership interest in K2 Wind to a third party for total proceeds of $216 million. The Company recorded a pre-tax gain on disposal of joint venture of $159 million. The Company received cash proceeds of $126 million on December 31, 2018 and $90 million in January 2019, which was recorded as trade and other receivables as at December 31, 2018.

The Company's equity-accounted investment in K2 Wind immediately prior to disposal was $41 million and there was a pre-tax accumulated loss of $16 million related to cash flow hedges of the K2 Wind equity investment, which was recorded within accumulated other comprehensive income. This accumulated loss was reclassified to net income within the gain on disposal, upon close of the transaction and is reflected within the gain on disposal disclosed above.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

33. Interests in joint arrangements, continued:

Joint ventures, continued

The summarized financial information of York Energy is as follows:

Statements of Financial Position	2019	2018
Cash and cash equivalents	$ 6	$ 3
Other current assets	11	15
Non-current assets [4]	221	226
Financial current liabilities	(16)	(15)
Other current liabilities	(3)	(3)
Financial non-current liabilities	(229)	(238)
Other non-current liabilities	(3)	(2)
Net assets	$ (13)	$ (14)

[4] York Energy has restricted cash of $9 million (2018 - $7 million) included in non-current assets above which represents security for a standby line of credit with a third party.

Statements of Income and Comprehensive Income	2019	2018
Revenues	$ 62	$ 60
Energy purchases and fuel	(8)	(8)
Other raw materials and operating charges	(4)	(4)
Other administrative expense	(1)	(1)
Depreciation and amortization	(9)	(9)
Finance expense	(15)	(13)
Net income and comprehensive income	$ 25	$ 25

A reconciliation of the Company's recorded equity investment in York Energy is as follows:

	2019	2018
Equity-accounted investment in York Energy, as at January 1	$ 142	$ 151
Proportionate share of comprehensive income (50%)	13	13
Distributions received – operating	(12)	(11)
Amortization of the Company's fair value of net assets acquired	(11)	(11)
Equity-accounted investment in York Energy, as at December 31	$ 132	$ 142

York Energy is party to a number of long-term transportation contracts and an operating and maintenance contract. The Company's share of approximate future payments for transportation contracts is $7 million in 2020, $25 million from 2021 to 2024 and $21 million after five years. The Company's share of approximate future payments for the operating and maintenance contract is $1 million in 2020 and $12 million from 2021 to 2025.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

33. Interests in joint arrangements, continued:

Joint ventures, continued

The summarized financial information of K2 Wind is as follows:

Statements of Income and Comprehensive Income	2018 [5]
Revenues	$ 105
Other raw materials and operating charges	(10)
Other administrative expense	(5)
Depreciation and amortization	(30)
Finance expense	(31)
Net income	29
Other comprehensive income:	
Unrealized gains on derivative instruments	13
Reclassification of losses on derivative instruments to net income for the year	8
Total comprehensive income	$ 50

[5] In November 2018, the Company announced the sale of K2 Wind and reclassified its interest in K2 Wind to held-for-sale, effective October 31, 2018. Equity accounting ceased at the time of reclassification and a distribution of $3 million received in December 2018 was recorded as other income on the Company's consolidated statement of income. The 2018 statement of income and comprehensive income for K2 Wind reflects the results of K2 Wind through October 31, 2018.

A reconciliation of the Company's recorded equity investment in K2 Wind is as follows:

	2018
Equity-accounted investment in K2 Wind, as at January 1	$ 33
Proportionate share of comprehensive income (33.33%)	17
Distributions received – operating	(16)
Adjustments for differences in accounting policies	7
Disposal of investment in K2 Wind	(41)
Equity-accounted investment in K2 Wind, as at December 31	$ -

34. Commitments and contingencies:

(a) The Company is party to a series of agreements with an external party to develop, build and own a 50% interest in Genesee 4 and 5 located in central Alberta. The Company expects to invest approximately $820 million, including capitalized borrowing costs, into Genesee 4 and 5. Continuation and timing of the Genesee 4 and 5 project will be considered once sufficient Alberta market certainty exists and new generation is required in Alberta to balance supply and demand. The Genesee 4 and 5 project has received all regulatory approvals required and it is expected that the two parties will build, own and operate Genesee 4 and 5, which would operate as a joint arrangement. In conjunction with the joint arrangement, the parties would be subject to various commercial agreements, including an eight-year tolling agreement. Under the tolling agreement, 50% of Capital Power's share of the output will be sold to the other party to the joint arrangement when commercial operations begin.

(b) The Whitla Wind project is a 299 MW wind facility in Southeast Alberta to be developed in two phases. The first 202 MW phase of the Whitla Wind project (Whitla Wind 1) commenced commercial operations during the fourth quarter of 2019. The Company is now proceeding with the 97 MW second phase of the Whitla Wind project (Whitla Wind 2) and expects the construction cost for Whitla Wind 2 to be approximately $165 million with an expected commercial operation date in 2021.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

34. Commitments and contingencies, continued:

(c) The Cardinal Point Wind project is a 150 MW wind facility under development in the McDonough and Warren Counties, Illinois. Cardinal Point Wind will operate under a 12-year fixed price contract with an investment-grade U.S. financial institution covering 85% of the facility's output beginning in 2021. Under the contract, Capital Power will swap the market revenue of the facility's generation for a fixed-price payment over a 12-year term. Fixed-price REC contracts have been secured with three Illinois utilities for a period of 15 years. The Company's original projected construction costs for the project were expected to be between $289 million and $301 million (US$236 million to US$246 million), with $256 million spent through December 31, 2019 (US$193 million) and an estimated $71 million (US$53 million) to be spent in 2020. The facility is expected to begin commercial operations in March of 2020.

(d) The Company is party to a number of long-term energy purchase and transportation contracts, operating and maintenance contracts and contracts to purchase environmental credits. Some of the energy purchase and transportation contracts are measured at their fair value and recorded on the consolidated statement of financial position as derivative financial instruments assets and liabilities as appropriate.

Approximate future payments under each group of contracts are as follows:

	Energy purchase and transportation contracts[1]	Operating and maintenance contracts	Environmental credits
Within one year	$ 189	$ 60	$ 30
Between one and five years	212	193	8
After five years	446	217	6
	$ 847	$ 470	$ 44

[1] Based on gross settlement amounts.

(e) Capital Power participated in the Line Loss Rule (LLR) Proceeding before the Alberta Utilities Commission (AUC) regarding loss factors that form the basis for certain transmission charges paid by Alberta generators, including Capital Power. The LLR Proceeding addressed the replacement of the non-compliant LLR, as well as the possible correction of line loss charges and credits for the years 2006 up to and including 2016.

The Company is participating in legal or regulatory processes rendering the final outcome of the LLR Proceeding still unknown. However, based on current AUC decisions, Capital Power would incur additional charges related to historical periods and, as such, has recorded a provision of $15 million pertaining to the estimated net liability for its currently held Alberta assets. The recorded provision reflects the Company's estimated net liability. It is expected that the invoicing process will result in gross billings to Capital Power of which those amounts not attributable to Capital Power will then be recovered from the appropriate parties. Though the Alberta Electric System Operator indicated that invoicing for the line loss adjustments would not occur until 2021, it is now seeking an order from the AUC to accelerate and commence the process in 2020. Until such an order is granted, however, no change in timing for invoicing is expected. As a result, the estimated net liability is classified as a non-current provision at December 31, 2019. Upon closing of the acquisition of the additional 50% interest in Genesee 3 and divestiture of the Company's interest in Keephills 3 (note 5) on October 1, 2019, the Company recorded a $6 million increase to the provision in the fourth quarter of 2019 within energy purchases and fuel, which increased the previously recorded provision of $9 million. The increase in the provision is a result of Genesee 3 being an older asset which therefore has greater exposure to the retroactive line loss adjustments.

(f) The Company has contingent consideration payable upon reaching specified milestones in connection with the development sites acquired in connection with the acquisition of Element Power US, LLC in 2014. As at December 31, 2019, contingent consideration of $5 million (US$4 million) (2018 - $12 million (US$9 million)) is recorded in non-current other liabilities. The valuation model for contingent consideration is based on the present value of the expected payment discounted using a risk-adjusted discount rate of 8%. The expected payment is determined by considering the possible scenarios for the development sites reaching specified milestones, the amount to be paid under each scenario and the probability of each scenario.

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

34. Commitments and contingencies, continued:

(g) The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

35. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $239 million (2018 - $271 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

36. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation facilities within Canada (Alberta, British Columbia and Ontario) and in the U.S. (North Carolina, New Mexico, Kansas, Alabama, Arizona and North Dakota), as this is how management assesses performance and determines resource allocations. The Company also holds a portfolio of wind and solar development sites in the U.S., including Cardinal Point Wind which is under development in Illinois.

The Company's results from operations within each geographic area are:

	Year ended December 31, 2019				Year ended December 31, 2018 (note 2(c))			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 1,221	$ 492	$ -	$ 1,713	$ 1,068	$ 204	$ -	$ 1,272
Revenues - inter-area	24	6	(30)	-	21	25	(46)	-
Other income	193	57	-	250	65	80	-	145
Total revenues and other income	$ 1,438	$ 555	$ (30)	$ 1,963	$ 1,154	$ 309	$ (46)	$ 1,417

	As at December 31, 2019			As at December 31, 2018 (note 2(c))		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 4,555	$ 1,534	$ 6,089	$ 3,947	$ 1,409	$ 5,356
Right-of-use assets (note 17)	61	34	95	-	-	-
Intangible assets	615	145	760	249	224	473
Goodwill	35	-	35	35	-	35
Other assets	53	-	53	65	1	66
	$ 5,319	$ 1,713	$ 7,032	$ 4,296	$ 1,634	$ 5,930

(Tabular amounts in millions of Canadian dollars, except share and per share amounts)

36. Segment information, continued:

The Company's revenues and other income from contracts with customers are disaggregated by major type of revenues and operational groupings of revenues:

	Year ended December 31, 2019						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 604	$ 9	$ 249	$ 185	$ 1,047	$ 617	$ 1,664
Emission credit revenues	23	-	-	8	31	18	49
Total revenues [1]	$ 627	$ 9	$ 249	$ 193	$ 1,078	$ 635	$1,713

[1] Included within trade and other receivables, as at December 31, 2019, were amounts related to contracts with customers of $109 million.

	Year ended December 31, 2018 (note 2(c))						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 525	$ 7	$ 138	$ 121	$ 791	$ 431	$ 1,222
Emission credit revenues	23	-	-	7	30	20	50
Total revenues [2]	$ 548	$ 7	$ 138	$ 128	$ 821	$ 451	$1,272

[2] Included within trade and other receivables, as at December 31, 2018, were amounts related to contracts with customers of $196 million.

37. Subsequent event:

Approval of normal course issuer bid

Subsequent to the end of 2019, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 10.5 million of its outstanding common shares during the one-year period from February 26, 2020 to February 25, 2021.

38. Comparative figures:

Certain comparative figures have been reclassified to conform to the current year's presentation.