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Capital Power reports fourth quarter and year-end 2018 results

Company has excellent year highlighted by strong cash flow generation

EDMONTON, Alberta – Capital Power Corporation (TSX: CPX) today released financial results for the quarter ended December 31, 2018.

Fourth Quarter Highlights

- Completed 99 megawatt New Frontier Wind project on-schedule and below budget
- Completed the sale of its minority owned interest in K2 Wind for a pre-tax gain of $159 million
- Generated net cash flows from operating activities of $133 million and adjusted funds from operations of $80 million
- Purchased and cancelled 0.8 million common shares under the Normal Course Issuer Bid

Net cash flows from operating activities were $133 million in the fourth quarter of 2018 compared with $75 million in the fourth quarter of 2017. Adjusted funds from operations (AFFO) were $80 million in the fourth quarter of 2018, compared to $94 million in the fourth quarter of 2017.

Net income attributable to shareholders in the fourth quarter of 2018 was $141 million and basic earnings per share was $1.27 per share, compared with net loss attributable to shareholders of $10 million, and basic loss per share of $0.20, in the comparable period of 2017. Normalized earnings attributable to common shareholders in the fourth quarter of 2018, after adjusting for non-recurring items and fair value adjustments, were $34 million or $0.33 per share compared with $25 million or $0.24 per share in the fourth quarter of 2017.

Net cash flows from operating activities were $450 million for the year ended December 31, 2018 compared with $372 million in 2017. Adjusted funds from operations were $397 million in 2018, compared with $361 million in 2017.

For the year ended December 31, 2018, net income attributable to shareholders was $274 million and basic earnings per share was $2.25 per share compared with $144 million and $1.07 per share in 2017. For the year ended December 31, 2018, normalized earnings attributable to common shareholders were $124 million, or $1.20 per share, compared with $113 million, or $1.12 per share in 2017.

“In 2018, Capital Power met or exceeded its annual operating and financial targets while adding 679 megawatts of contracted generation through the acquisition of Arlington Valley and completion of the New Frontier Wind project,” said Brian Vaasjo, President and CEO of Capital Power. “We have seen a recovery in Alberta power prices that averaged $50 per megawatt hour in 2018 and contributed to the strong financial results. The company generated AFFO of $397 million that was at the high end of the target range of $360 million to $400 million and represented an increase of 10% from 2017.”

“For 2019, we are targeting a 22% increase in AFFO based on the midpoint of our $460 million to $510 million target range, primarily due to a full year of contributions from assets added in late 2018 and higher Alberta power prices, and remain on track to meet our target. We continue to be focused on growing contracted cash flows and have committed $500 million of capital for contracted growth to support a sustainable and growing dividend to our shareholders including a recent extension to 2021 for our 7%

annual dividend growth guidance," added Mr. Vaasjo.

The Company continued to be active with its Normal Course Issuer Bid (NCIB) by purchasing and cancelling 0.8 million common shares at an average exercise price of $26.79 per share for a total cost of $21 million in the fourth quarter. In 2018, the Company purchased and cancelled 3.0 million common shares at an average exercise price of $25.28 per share for a total cost of $76 million. Under its TSX approved NCIB, the Company can purchase and cancel up to 9.3 million common shares during the one-year period ending February 20, 2019.

Operational and Financial Highlights [1] (unaudited)	**Three months ended December 31**				**Year ended December 31**			
(millions of dollars except per share and operational amounts)		**2018**		**2017**		**2018**		**2017**
Electricity generation (Gigawatt hours)		5,406		4,839		20,229		17,194
Generation facility availability		94%		95%		95%		96%
Revenues and other income	$	335	$	261	$	1,394	$	1,146
Adjusted EBITDA [2]	$	113	$	154	$	646	$	551
Net income (loss)	$	139	$	(13)	$	267	$	134
Net income (loss) attributable to shareholders of the Company	$	141	$	(10)	$	274	$	144
Basic and diluted earnings (loss) per share	$	1.27	$	(0.20)	$	2.25	$	1.07
Normalized earnings attributable to common shareholders [2]	$	34	$	25	$	124	$	113
Normalized earnings per share [2]	$	0.33	$	0.24	$	1.20	$	1.12
Net cash flows from operating activities	$	133	$	75	$	450	$	372
Adjusted funds from operations [2, 3]	$	80	$	94	$	397	$	361
Adjusted funds from operations per share [2]	$	0.78	$	0.90	$	3.85	$	3.58
Purchase of property, plant and equipment and other assets	$	114	$	42	$	355	$	218
Dividends per common share, declared	$	0.4475	$	0.4175	$	1.730	$	1.615

1 The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the audited consolidated financial statements for the year ended December 31, 2018.

2 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, and gains or losses on disposals (adjusted EBITDA), normalized earnings attributable to common shareholders, normalized earnings per share, adjusted funds from operations and adjusted funds from operations per share are non-GAAP financial measures and do not have standardized meanings under GAAP and are, therefore, unlikely to be comparable to similar measures used by other enterprises. See Non-GAAP Financial Measures.

3 Commencing with the Company's March 31, 2018 quarter-end, the reported adjusted funds from operations measure was refined to better reflect the purpose of the measure (see Non-GAAP Financial Measures). The applicable comparable periods have been adjusted to conform to the current period's presentation.

Significant Events

Disposal of interest in K2 Wind joint venture

On December 31, 2018, Capital Power completed the sale of its minority owned interest in K2 Wind to a consortium of investors led by Axium Infrastructure (Axium Consortium) for proceeds of $216 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 recorded a pre-tax gain on disposal of joint venture of $159 million. The Company's equity investment in K2 Wind immediately prior to disposal was $41 million and there was an 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 loss was reclassified to net income upon close of the transaction and is reflected as a reduction within the gain on disposal disclosed above.

New Frontier Wind begins commercial operation

On December 21, 2018, New Frontier Wind, a 99 MW facility in McHenry County, North Dakota, began commercial operations. The construction of the facility was completed on-schedule and below its original project cost estimate of approximately $182 million (US$145 million). On December 31, 2018, Capital Power received approximately $125 million (US$92 million) in net tax equity financing from J.P. Morgan in exchange for Class A interests in a subsidiary of the Company.

Capital Power will operate New Frontier Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 87% of the facility's output. Under the contract, Capital Power will swap the market revenue from a fixed volume of New Frontier Wind's generation for a fixed price payment over a 12-year term.

Acquisition of Arlington Valley

On September 6, 2018, the Company announced it entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington facility), a 580 megawatt (MW) combined cycle natural gas generation facility, from funds managed by Oaktree Capital Management, L.P. and its co-investors. On November 30, 2018, the Company completed the acquisition of Arlington Valley for a total of $399 million (US$303 million), including preliminary working capital and other closing adjustments of $3 million (US$3 million). Capital Power financed the transaction using its credit facilities followed by permanent debt financing (see Subsequent Events).

The Arlington facility sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under tolling agreements through 2025. The Arlington facility is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the Desert Southwest (DSW) or the California Independent System Operator (CAISO) wholesale markets during the months outside the summer tolling months.

The acquisition of the Arlington facility supports the Company's U.S. growth strategy and fully meets the Company's investment criteria. The Arlington facility is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment. In addition to meeting the Company's expected return criteria, the investment contributes to the Company's dividend growth strategy through immediate AFFO accretion supported by contracted cash flows to the end of 2025 with a high probability of re-contracting as confirmed through third-party market assessments.

The Arlington facility is expected to generate approximately US$62 million of adjusted EBITDA and US$44 million of AFFO in 2019 during the last year of its current toll. Subsequently, adjusted EBITDA averages US$35 million per year (ranging from US$32 million to US$38 million) and US$16 million of AFFO during the 6-year period from 2020 to 2025. Based on the expected financing, the 5-year average accretion for AFFO is expected to be $0.22 per share reflecting a 6% increase. The average accretion to earnings is expected to be $0.03 per share in the first 5 years, representing a 2% increase.

Dividend increase

On July 27, 2018, the Company's Board of Directors approved an increase of 7% in the annual dividend for holders of its common shares, from $1.67 per common share to $1.79 per common share. This increased common dividend commenced with the third quarter 2018 quarterly dividend payment on October 31, 2018 to shareholders of record at the close of business on September 28, 2018.

Genesee contracted physical natural gas capacity

During the second quarter of 2018, Capital Power secured additional physical natural gas delivery capacity for the Genesee site. This capacity is expected to enable increased natural gas co-firing as early as 2020 and allows for full conversion to natural gas as early as 2020.

Genesee royalty rate agreement

During the second quarter, Capital Power entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980's. The new structure provides improved royalty cost certainty in the future.

Investment in C2CNT

In May 2018, Capital Power acquired a 5% equity interest in C2CNT, a company that developed and is now testing at scale an innovative technology that captures and transforms carbon dioxide (CO_2) into a useful and high-value product called carbon nanotubes, for total consideration of $3.2 million (US$2.5 million). This technology will take CO_2 from many sources including emissions from thermal power generation and other industrial processes and convert it into a carbon-based product that can be used in various industries. This investment in C2CNT supports Capital Power's pursuit of innovative and leading-edge technology and approaches that have the potential to reduce greenhouse gases. Included with the acquisition is an option that may be elected prior to March 1, 2020 to increase the Company's equity interest in C2CNT by an additional 20%.

Bloom Wind tax equity agreement amendment

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom Wind. As a result, in May of 2018, the Company re-negotiated certain commercial terms within the tax equity agreement for Bloom Wind. The re-negotiated terms of the Bloom Wind tax equity agreement resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US$33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms of the tax-equity agreement resulted in a one-time, non-cash increase in net income after tax of $15 million (US$11 million). Under the re-negotiated tax equity agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for the project.

Completion of contracts for Cardinal Point Wind

On April 30, 2018, Capital Power announced that the construction of Cardinal Point Wind will proceed once all applicable regulatory approvals are received. Cardinal Point Wind is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020. Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. 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. In addition, the Cardinal Point Wind project has secured 15-year, fixed-price Renewable Energy Credit (REC) contracts with three Illinois utilities. The REC and output contracts will secure long-term predictable revenues, allowing Cardinal Point Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its third wind development project in the growing U.S. renewables market.

Executive appointment

Consistent with the Company's ongoing commitment to sustainability, during the second quarter of 2018, the Company named Senior Vice President, Kate Chisholm, its Chief Legal and Sustainability Officer, and sustainability was added to the Board of Directors' mandate.

<u>Subsequent Events</u>

$300 million medium-term note issuance

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. The net proceeds of the offering will be used to repay indebtedness under the Company's credit facilities or for general corporate purposes.

Approval of normal course issuer bid

Subsequent to the end of 2018, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 9.0 million of its outstanding common shares during the one-year period from February 21, 2019 to February 20, 2020.

<u>Analyst conference call and webcast</u>

Capital Power will be hosting a conference call and live webcast with analysts on February 19, 2019 at 9:00 am (MT) to discuss the fourth quarter financial results. The conference call dial-in numbers are:

(604) 638-5340 (Vancouver)
(403) 351-0324 (Calgary)
(416) 915-3239 (Toronto)
(514) 375-0364 (Montreal)
(800) 319-4610 (toll-free from Canada and USA)

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conclusion of the analyst conference call.

<u>Non-GAAP Financial Measures</u>

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, and gains or losses on disposals (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations 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.

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

(unaudited, $ millions)	Year ended December 31		Three months ended							
	2018	2017	Dec 2018	Sep 2018	Jun 2018	Mar 2018	Dec 2017	Sep 2017	Jun 2017	Mar 2017
Revenues and other income	1,394	1,146	335	389	363	307	261	346	201	338
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(799)	(650)	(233)	(261)	(152)	(153)	(125)	(198)	(119)	(208)
Adjusted EBITDA from joint ventures [1]	51	55	11	10	12	18	18	10	14	13
Adjusted EBITDA	**646**	**551**	**113**	**138**	**223**	**172**	**154**	**158**	**96**	**143**
Depreciation and amortization	(300)	(271)	(77)	(74)	(74)	(75)	(72)	(74)	(65)	(60)
Impairments	-	(83)	-	-	-	-	-	(83)	-	-
Gain on disposal of joint venture (see Significant Events)	159	-	159	-	-	-	-	-	-	-
Foreign exchange gain (loss)	10	28	6	(2)	3	3	(4)	21	9	2
Net finance expense	(123)	(108)	(33)	(28)	(29)	(33)	(32)	(31)	(25)	(20)
Finance expense and depreciation expense from joint ventures [1]	(32)	(24)	(10)	(7)	(8)	(7)	(13)	(6)	(2)	(3)
Income tax (expense) recovery	(93)	41	(19)	(8)	(47)	(19)	(46)	8	94	(15)
Net income (loss)	**267**	**134**	**139**	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**
Net income (loss) attributable to:										
Non-controlling interests	(7)	(10)	(2)	(1)	(2)	(2)	(3)	(2)	(2)	(3)
Shareholders of the Company	274	144	141	20	70	43	(10)	(5)	109	50
Net income (loss)	**267**	**134**	**139**	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**

[1] Total income from joint ventures as per the Company's consolidated statements of income.

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. Commencing with the Company's March 31, 2018 quarter-end, the Company made several adjustments to its adjusted funds from operations measure to better reflect the purpose of the measure. These changes included the following:

- The reduction for sustaining capital expenditures historically included costs associated with the Company's Genesee performance standard project. These costs have been considered further and given that the intent of this project is to improve efficiency of the facility, management considers these costs to be growth in nature, and hence they should not be considered sustaining capital expenditures that would be deducted in the adjusted funds from operations measure.
- In prior periods, there has been an addback included for Part VI.1 preferred dividend tax impacts which effectively contemplated the associated tax deduction related to preferred share dividends that reduced current tax payable. Upon further consideration, since that deduction offsets the cash tax payable related to Part VI.1 preferred dividend taxes, the cash effects of the preferred dividend tax impacts should offset. The remaining impact to adjusted funds from operations should therefore be the current income tax expense without any adjustment pertaining to preferred dividend tax impacts.
- Historically, the impacts of tax equity financing structures on adjusted funds from operations have been insignificant. With the commencement of commercial operations of Bloom Wind in 2017, management has revisited the flow of these operations through the adjusted funds from operations metric. Similar to the treatment of joint venture interests, the treatment of assets under tax equity financing structures has been adjusted to reflect the Company's share of the adjusted funds from operations of these assets within consolidated adjusted funds from operations. To give effect to this change, the deduction for net finance expense now excludes non-cash implicit interest expense pertaining to tax equity financing structures. However, a deduction is made to remove the tax equity project investors' respective shares of the adjusted funds from operations of the assets under tax equity financing structures, as determined by their shares of the distributable cash of the respective operations.

Comparative figures have been restated to reflect the above refinements to the adjusted funds from operations metric.

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.

Commencing with the quarter ended March 31, 2018, the Company began presenting adjusted funds from operations per share. This metric 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	
	2018	**2017**	**2018**	**2017**
Net cash flows from operating activities per consolidated statements of cash flows	**450**	**372**	**133**	**75**
Add (deduct) items included in calculation of net cash flows from operating activities per consolidated statements of cash flows:				
Interest paid	96	81	26	26
Change in fair value of derivatives reflected as cash settlement	(21)	5	(5)	(1)
Distributions received from joint ventures	(30)	(27)	(6)	(5)
Miscellaneous financing charges paid [1]	6	5	2	1
Income taxes paid	2	2	-	-
Change in non-cash operating working capital	43	40	(19)	40
	96	106	(2)	61
Net finance expense [2]	(97)	(92)	(25)	(27)
Current income tax expense	(18)	(16)	(3)	(5)
Sustaining capital expenditures [3]	(79)	(59)	(25)	(13)
Preferred share dividends paid	(41)	(35)	(11)	(10)
Cash received from coal compensation	50	50	-	-
Remove tax equity interests' respective shares of adjusted funds from operations	(7)	(5)	(2)	(1)
Adjusted funds from operations from joint ventures	43	40	15	14
Adjusted funds from operations	**397**	**361**	**80**	**94**
Weighted average number of common shares outstanding (millions)	**103.0**	**100.7**	**102.3**	**104.3**
Adjusted funds from operations per share ($)	**3.85**	**3.58**	**0.78**	**0.90**

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 Includes sustaining capital expenditures net of partner contributions of $8 million and $9 million for the years ended December 31, 2018 and 2017, 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							
	2018	2017	Dec 2018	Sep 2018	Jun 2018	Mar 2018	Dec 2017	Sep 2017	Jun 2017	Mar 2017
Basic earnings (loss) per share ($)	**2.25**	**1.07**	**1.27**	**0.10**	**0.57**	**0.32**	**(0.20)**	**(0.13)**	**1.03**	**0.44**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income (loss)	**274**	**144**	**141**	**20**	**70**	**43**	**(10)**	**(5)**	**109**	**50**
Preferred share dividends including Part VI.1 tax	(42)	(36)	(11)	(10)	(11)	(10)	(11)	(9)	(8)	(8)
Earnings (loss) attributable to common shareholders	232	108	130	10	59	33	(21)	(14)	101	42
Unrealized changes in fair value of derivatives [1]	67	(1)	35	26	(19)	25	14	(31)	23	(7)
Gain on disposal of joint venture (see Significant Events)	(134)	-	(134)	-	-	-	-	-	-	-
Non-Cash tax equity adjustment (see Significant Events)	(15)	-	-	-	(15)	-	-	-	-	-
Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments	(29)	12	-	-	-	(29)	-	12	-	-
Asset held for sale accounting treatment of K2 Wind	3	-	3	-	-	-	-	-	-	-
Income tax adjustment	-	-	-	-	(2)	2	-	-	-	-
Impairments	-	53	-	-	-	-	-	53	-	-
Unrealized foreign exchange loss (gain) on revaluation of U.S. dollar denominated debt	-	30	-	-	-	-	(1)	44	(12)	(1)
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	(36)	-	-	-	-	(1)	(35)	-	-
Recognition of U.S. deferred tax assets related to non-capital losses	-	(86)	-	-	-	-	-	-	(86)	-
Provision for Line Loss Rule Proceeding	-	7	-	-	-	-	7	-	-	-
U.S. tax reform rate decrease	-	31	-	-	-	-	31	-	-	-
Success fee received related to development project	-	(3)	-	-	-	-	(3)	-	-	-
Release of tax liability on foreign domiciled investment	-	(2)	-	-	-	-	(1)	-	-	(1)
Normalized earnings attributable to common shareholders	**124**	**113**	**34**	**36**	**23**	**31**	**25**	**29**	**26**	**33**
Weighted average number of common shares outstanding (millions)	103.0	100.7	102.3	102.4	103.1	104.2	104.3	104.1	98.1	96.3
Normalized earnings per share ($)	**1.20**	**1.12**	**0.33**	**0.35**	**0.22**	**0.30**	**0.24**	**0.28**	**0.27**	**0.34**

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.

Forward-looking Information

Forward-looking information or statements included in this press release 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 press release 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 press release includes disclosures regarding 2019 targets, including the AFFO guidance range and targeted capital commitments, future dividend growth, expectations pertaining to the construction cost and commercial operations date for Cardinal Point Wind and expectations pertaining to the acquisition of Arlington Valley (see Significant Events). Such expectations around the Arlington Valley acquisition include impacts of the acquisition on adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA and the re-contracting of the Arlington Valley facility.

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: (i) electricity, other energy and carbon prices, (ii) performance, (iii) business prospects (including potential re-contracting opportunities) and opportunities including expected growth and capital projects, (iv) status of and impact of policy, legislation and regulations, (v) effective tax rates, and (vi) anticipated performance of the acquired Arlington Valley facility (see Significant Events).

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: (i) changes in electricity prices in markets in which the Company operates, (ii) changes in energy commodity market prices and use of derivatives, (iii) regulatory and political environments including changes to environmental, financial reporting, market structure and tax legislation, (iv) generation facility availability and performance including maintenance of equipment, (v) ability to fund current and future capital and working capital needs, (vi) acquisitions and developments including timing and costs of regulatory approvals and construction, (vii) changes in market prices and availability of fuel, (viii) ability to realize the anticipated benefits of the Arlington Valley acquisition, (ix) limitations inherent in the Company's review of acquired assets and (x) changes in general economic and competitive conditions. See Risks and Risk Management in the Company's Management's Discussion and Analysis for the year ended December 31, 2018, prepared as of February 15, 2019, 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.

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CAPITAL POWER CORPORATION

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), prepared as of February 15, 2019, should be read in conjunction with the audited consolidated financial statements of Capital Power Corporation and its subsidiaries for the years ended December 31, 2018 and December 31, 2017, the annual information form of Capital Power Corporation for the year ended December 31, 2018 and the cautionary statements regarding forward-looking information which begin on page 12. 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, 2018, 2017 and 2016 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 15, 2019.

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 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 phase 1 of the Whitla Wind project, and the Cardinal Point Wind project)
- facility availability and planned outages,
- capital expenditures for facility maintenance and other (sustaining capital, future growth projects),
- the impact of the transition to a capacity market on the Company's future growth projects including the Genesee 4 and 5 project,
- expectations pertaining to the financial impacts of the acquisition of Arlington Valley (see Significant Events), including the impacts to adjusted funds from operations, adjusted funds from operations per share and adjusted EBITDA,
- re-contracting of the Arlington Valley facility,
- expectations around the Line Loss Rule Proceeding including timing of retrospective loss factors being finalized, participation in applicable appeal processes, and potential impacts to the Company, and
- impacts of future IFRS standards and amendments.

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 2019 sections, and
- anticipated performance of the acquired Arlington Valley facility (see Significant Events).

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 Arlington Valley acquisition,
- 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 5,100 megawatts (MW) of power generation capacity at 25 facilities across North America. Approximately 900 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) and Capital Power (US Holdings) Inc., both wholly owned subsidiaries of the Company.

CORPORATE STRATEGY

Capital Power's corporate strategy is based on its vision to be recognized as one of North America's most respected, reliable and competitive power generators. 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.

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

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

(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.

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 2018, the Company commenced commercial operation of the New Frontier Wind project (New Frontier Wind), received Alberta Utilities Commission approval and commenced construction on the Whitla Wind project (Whitla Wind), and completed the acquisition of the Arlington Valley facility (see Significant Events). The continuation and timing of the Genesee 4 and 5 project will be considered once more Alberta market certainty exists and new generation is required in Alberta to balance supply and demand.

The Company is assessing a number of additional projects in various stages of development, including future uses of the Genesee site and potential conversions of the Company's coal-fired generation facilities to natural gas, and it continues to evaluate acquisition prospects to strengthen its existing portfolio. 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	2018 target	2018 actual results
Facility availability average	95% or greater	95%
Sustaining capital expenditures	$85 million	$79 million [1]
Genesee performance standard expenditures [2]	$15 million	$11 million
Facility operating and maintenance expenses	$230 million to $250 million	$238 million

1 Includes sustaining capital expenditures net of joint venture contributions of $8 million.

2 This project is designed to reduce CO_2 emissions and improve the efficiency of the Company's coal-fired facilities in response to the Alberta Climate Leadership Plan (CLP).

The Company's facility availability averaged 95% which reflected planned outages at York Energy, Shepard, Joffre, Clover Bar Energy Centre, Roxboro, Southport, Decatur Energy, and Genesee. Unplanned outages also occurred at Keephills 3, Decatur Energy, Southport and Clover Bar Energy Centre.

Sustaining capital expenditures were lower than target largely due to lower than expected mine capital spending and lower than expected Genesee 2 planned outage spending. Partially offsetting the favourable variance was higher than expected Keephills 3 mine capital expenditures. Expenditures for the Genesee performance standard were lower than target primarily due to project savings.

The facility operating and maintenance expenses target includes other raw materials and operating charges, staff costs and employee benefits expense and other administrative expense for the Company's facilities. The actual results for 2018 were consistent with the target range.

Disciplined growth

Performance measure	2018 target	Status as at December 31, 2018
New Frontier Wind	Complete New Frontier Wind on time and on budget.	Construction completed on time and under budget in December 2018.
Whitla Wind	Progress on the development of Whitla Wind to be on track with budget and the 2019 completion date.	Turbine supply agreement signed during the second quarter of 2018, Alberta Utilities Commission approval has been received and construction has commenced. Construction is expected to be complete and on budget in the fourth quarter of 2019.
New development	Execute contracts for the output of one to three new wind developments.	Completed contracts for Cardinal Point Wind (see Significant Events).

Financial stability and strength

Performance measure	2018 target	2018 actual results
Adjusted funds from operations [1]	$360 million to $400 million	$397 million

1 Adjusted funds from operations is a non-GAAP measure. See Non-GAAP Financial Measures.

OUTLOOK AND TARGETS FOR 2019

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 2018, the Company provided financial guidance for 2019 adjusted funds from operations (see Non-GAAP Financial Measures) in the range of $460 million to $510 million. The 2019 guidance was based on approximately 70% of the Alberta commercial baseload generation portfolio sold forward at an average contracted price in the low-$50 per megawatt hour (MWh) range.

Priorities for the Company in 2019 will include continuing to work with the Government of Alberta concerning the transition away from an energy-only market to a capacity market. The Company will continue to develop its wind facilities with Whitla Wind and Cardinal Point Wind expected to commence commercial operation in the fourth quarter of 2019 and the first quarter of 2020, respectively. The Company is targeting committed capital of $500 million for contracted growth in 2019.

In 2019, Capital Power's availability target of 95% reflects major scheduled maintenance outages for Genesee 1, Clover Bar Energy Centre, Joffre, Shepard, and Decatur Energy compared to those scheduled for Genesee 2, Genesee 3, Clover Bar Energy Centre, Joffre, Shepard, East Windsor, and Decatur Energy in 2018.

The Alberta portfolio position, contracted prices and forward Alberta pool prices for 2019, 2020 and 2021 (all as at December 31, 2018) were:

Alberta commercial portfolio positions and power prices	2019	2020	2021
Percentage of baseload generation sold forward [1]	78%	34%	1%
Contracted price [2]	Mid-$50	Low-$50	Low-$80 [3]
Forward Alberta pool prices	$54	$47	$45

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.

3 Average contract pricing on the net 2021 position is abnormally high due to low net volumes sold forward where gross sales were transacted at higher prices than gross purchases.

The 2019 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 2018, the Company extended the 7% annual dividend growth guidance for one additional year to 2021. 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 2019.

Performance measure targets for 2019

Performance measure	2019 target
Operational excellence	
Facility availability average	95% or greater
Sustaining capital expenditures	$80 to $90 million
Disciplined growth	
Whitla Wind	Completion of Whitla Wind on budget and on time for commercial operations in December 2019.
Cardinal Point Wind	Progress on the development of Cardinal Point Wind (see Significant Events) to be on track with budget and the March 2020 completion date.
Other contracted growth	$500 million of committed capital.
Financial stability and strength	
Adjusted funds from operations [1]	$460 million to $510 million
Adjusted EBITDA [1, 2]	$800 million to $850 million

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

2 Commencing with the Company's March 31, 2019 quarter-end, adjusted EBITDA will exclude unrealized changes in fair value of commodity derivatives and emission credits which were previously included in adjusted EBITDA. This change will be 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 will also result in period over period adjusted EBITDA being more comparable.

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, and gains or losses on disposals (adjusted EBITDA), (ii) adjusted funds from operations, (iii) adjusted funds from operations 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.

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

(unaudited, $ millions)	**Year ended December 31**		**Three months ended**							
	2018	**2017**	**Dec 2018**	**Sep 2018**	**Jun 2018**	**Mar 2018**	**Dec 2017**	**Sep 2017**	**Jun 2017**	**Mar 2017**
Revenues and other income	1,394	1,146	335	389	363	307	261	346	201	338
Energy purchases and fuel, other raw materials and operating charges, staff costs and employee benefits expense, and other administrative expense	(799)	(650)	(233)	(261)	(152)	(153)	(125)	(198)	(119)	(208)
Adjusted EBITDA from joint ventures [1]	51	55	11	10	12	18	18	10	14	13
Adjusted EBITDA	**646**	**551**	**113**	**138**	**223**	**172**	**154**	**158**	**96**	**143**
Depreciation and amortization	(300)	(271)	(77)	(74)	(74)	(75)	(72)	(74)	(65)	(60)
Impairments	-	(83)	-	-	-	-	-	(83)	-	-
Gain on disposal of joint venture (see Significant Events)	159	-	159	-	-	-	-	-	-	-
Foreign exchange gain (loss)	10	28	6	(2)	3	3	(4)	21	9	2
Net finance expense	(123)	(108)	(33)	(28)	(29)	(33)	(32)	(31)	(25)	(20)
Finance expense and depreciation expense from joint ventures [1]	(32)	(24)	(10)	(7)	(8)	(7)	(13)	(6)	(2)	(3)
Income tax (expense) recovery	(93)	41	(19)	(8)	(47)	(19)	(46)	8	94	(15)
Net income (loss)	**267**	**134**	**139**	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**
Net income (loss) attributable to:										
Non-controlling interests	(7)	(10)	(2)	(1)	(2)	(2)	(3)	(2)	(2)	(3)
Shareholders of the Company	274	144	141	20	70	43	(10)	(5)	109	50
Net income (loss)	**267**	**134**	**139**	**19**	**68**	**41**	**(13)**	**(7)**	**107**	**47**

1 Total income from joint ventures as per the Company's consolidated statements of income.

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. Commencing with the Company's March 31, 2018 quarter-end, the Company made several adjustments to its adjusted funds from operations measure to better reflect the purpose of the measure. These changes included the following:

- The reduction for sustaining capital expenditures historically included costs associated with the Company's Genesee performance standard project. These costs have been considered further and given that the intent of this project is to improve efficiency of the facility, management considers these costs to be growth in nature, and hence they should not be considered sustaining capital expenditures that would be deducted in the adjusted funds from operations measure.
- In prior periods, there has been an addback included for Part VI.1 preferred dividend tax impacts which effectively contemplated the associated tax deduction related to preferred share dividends that reduced current tax payable. Upon further consideration, since that deduction offsets the cash tax payable related to Part VI.1 preferred dividend taxes, the cash effects of the preferred dividend tax impacts should offset. The remaining impact to adjusted funds from operations should therefore be the current income tax expense without any adjustment pertaining to preferred dividend tax impacts.
- Historically, the impacts of tax equity financing structures on adjusted funds from operations have been insignificant. With the commencement of commercial operations of Bloom Wind in 2017, management has revisited the flow of these operations through the adjusted funds from operations metric. Similar to the treatment of joint venture interests, the treatment of assets under tax equity financing structures has been adjusted to reflect the Company's share of the adjusted funds from operations of these assets within consolidated adjusted funds from operations. To give effect to this change, the deduction for net finance expense now excludes non-cash implicit interest expense pertaining to tax equity financing structures. However, a deduction is made to remove the tax equity project investors' respective shares of the adjusted funds from operations of the assets under tax equity financing structures, as determined by their shares of the distributable cash of the respective operations.

Comparative figures have been restated to reflect the above refinements to the adjusted funds from operations metric.

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.

Commencing with the quarter ended March 31, 2018, the Company began presenting adjusted funds from operations per share. This metric 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	
	2018	**2017**	**2018**	**2017**
Net cash flows from operating activities per consolidated statements of cash flows	**450**	**372**	**133**	**75**
Add (deduct) items included in calculation of net cash flows from operating activities per consolidated statements of cash flows:				
Interest paid	96	81	26	26
Change in fair value of derivatives reflected as cash settlement	(21)	5	(5)	(1)
Distributions received from joint ventures	(30)	(27)	(6)	(5)
Miscellaneous financing charges paid [1]	6	5	2	1
Income taxes paid	2	2	-	-
Change in non-cash operating working capital	43	40	(19)	40
	96	106	(2)	61
Net finance expense [2]	(97)	(92)	(25)	(27)
Current income tax expense	(18)	(16)	(3)	(5)
Sustaining capital expenditures [3]	(79)	(59)	(25)	(13)
Preferred share dividends paid	(41)	(35)	(11)	(10)
Cash received from coal compensation	50	50	-	-
Remove tax equity interests' respective shares of adjusted funds from operations	(7)	(5)	(2)	(1)
Adjusted funds from operations from joint ventures	43	40	15	14
Adjusted funds from operations	**397**	**361**	**80**	**94**
Weighted average number of common shares outstanding (millions)	**103.0**	**100.7**	**102.3**	**104.3**
Adjusted funds from operations per share ($)	**3.85**	**3.58**	**0.78**	**0.90**

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 Includes sustaining capital expenditures net of partner contributions of $8 million and $9 million for the years ended December 31, 2018 and 2017, 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							
	2018	2017	Dec 2018	Sep 2018	Jun 2018	Mar 2018	Dec 2017	Sep 2017	Jun 2017	Mar 2017
Basic earnings (loss) per share ($)	**2.25**	**1.07**	**1.27**	**0.10**	**0.57**	**0.32**	**(0.20)**	**(0.13)**	**1.03**	**0.44**
Net income (loss) attributable to shareholders of the Company per Consolidated Statements of Income (loss)	**274**	**144**	**141**	**20**	**70**	**43**	**(10)**	**(5)**	**109**	**50**
Preferred share dividends including Part VI.1 tax	(42)	(36)	(11)	(10)	(11)	(10)	(11)	(9)	(8)	(8)
Earnings (loss) attributable to common shareholders	232	108	130	10	59	33	(21)	(14)	101	42
Unrealized changes in fair value of derivatives [1]	67	(1)	35	26	(19)	25	14	(31)	23	(7)
Gain on disposal of joint venture (see Significant Events)	(134)	-	(134)	-	-	-	-	-	-	-
Non-Cash tax equity adjustment (see Significant Events)	(15)	-	-	-	(15)	-	-	-	-	-
Realized foreign exchange (gain) loss on settlement of foreign currency derivative instruments	(29)	12	-	-	-	(29)	-	12	-	-
Asset held for sale accounting treatment of K2 Wind	3	-	3	-	-	-	-	-	-	-
Income tax adjustment	-	-	-	-	(2)	2	-	-	-	-
Impairments	-	53	-	-	-	-	-	53	-	-
Unrealized foreign exchange loss (gain) on revaluation of U.S. dollar denominated debt	-	30	-	-	-	-	(1)	44	(12)	(1)
Realized foreign exchange gain on revaluation of U.S. dollar denominated debt	-	(36)	-	-	-	-	(1)	(35)	-	-
Recognition of U.S. deferred tax assets related to non-capital losses	-	(86)	-	-	-	-	-	-	(86)	-
Provision for Line Loss Rule Proceeding	-	7	-	-	-	-	7	-	-	-
U.S. tax reform rate decrease	-	31	-	-	-	-	31	-	-	-
Success fee received related to development project	-	(3)	-	-	-	-	(3)	-	-	-
Release of tax liability on foreign domiciled investment	-	(2)	-	-	-	-	(1)	-	-	(1)
Normalized earnings attributable to common shareholders	**124**	**113**	**34**	**36**	**23**	**31**	**25**	**29**	**26**	**33**
Weighted average number of common shares outstanding (millions)	103.0	100.7	102.3	102.4	103.1	104.2	104.3	104.1	98.1	96.3
Normalized earnings per share ($)	**1.20**	**1.12**	**0.33**	**0.35**	**0.22**	**0.30**	**0.24**	**0.28**	**0.27**	**0.34**

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.

Normalized earnings per share reflects the period-over-period change in normalized earnings attributable to common shareholders, the changes from period to period in the weighted average number of common shares outstanding and the changes from period to period in net income attributable to non-controlling interests.

FINANCIAL HIGHLIGHTS

(unaudited, $ millions, except per share amounts)	Year ended December 31		
	2018	2017	2016
Revenues and other income	1,394	1,146	1,214
Adjusted EBITDA [1]	646	551	520
Net income	267	134	102
Net income attributable to shareholders of the Company	274	144	111
Normalized earnings attributable to common shareholders [1]	124	113	117
Basic and diluted earnings per share ($) [2]	2.25	1.07	0.91
Normalized earnings per share ($) [1]	1.20	1.12	1.22
Net cash flows from operating activities	450	372	375
Adjusted funds from operations [1]	397	361	291
Adjusted funds from operations per share ($) [1]	3.85	3.58	3.02
Purchase of property, plant and equipment and other assets	355	218	313
Dividends per common share, declared ($)	1.7300	1.6150	1.5100
Dividends per Series 1 preferred share, declared ($)	0.7650	0.7650	0.7650
Dividends per Series 3 preferred share, declared ($)	1.1500	1.1500	1.1500
Dividends per Series 5 preferred share, declared ($)	1.2173	1.1250	1.1250
Dividends per Series 7 preferred share, declared ($)	1.5000	1.5000	0.3616
Dividends per Series 9 preferred share, declared ($)	1.4375	0.5642	-

	As at December 31		
	2018	2017	2016
Loans and borrowings including current portion	2,647	2,146	1,508
Total assets	7,660	6,898	6,062

[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.

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. 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 2018 were higher compared with adjusted funds from operations for 2017, due to higher net cash flows from operating activities from the commencement of commercial operations of Bloom Wind and the acquisitions of the Veresen thermal facilities and Decatur Energy in the second quarter of 2017 and higher net cash flows from operating activities from the Alberta contracted facilities driven by the adjusted EBITDA increase described in Consolidated Net Income and Results of Operations. These increases were partially offset by higher net finance expense, higher preferred share dividends and higher sustaining capital expenditures.

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

SIGNIFICANT EVENTS

Disposal of interest in K2 Wind joint venture

On December 31, 2018, Capital Power completed the sale of its minority owned interest in K2 Wind to a consortium of investors led by Axium Infrastructure (Axium Consortium) for proceeds of $216 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 recorded a pre-tax gain on disposal of joint venture of $159 million. The Company's equity investment in K2 Wind immediately prior to disposal was $41 million and there was an 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 loss was reclassified to net income upon close of the transaction and is reflected as a reduction within the gain on disposal disclosed above.

New Frontier Wind begins commercial operation

On December 21, 2018, New Frontier Wind, a 99 MW facility in McHenry County, North Dakota, began commercial operations. The construction of the facility was completed on-schedule and below its original project cost estimate of approximately $182 million (US$145 million). On December 31, 2018, Capital Power received approximately $125 million (US$92 million) in net tax equity financing from J.P. Morgan in exchange for Class A interests in a subsidiary of the Company.

Capital Power will operate New Frontier Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 87% of the facility's output. Under the contract, Capital Power will swap the market revenue from a fixed volume of New Frontier Wind's generation for a fixed price payment over a 12-year term.

Acquisition of Arlington Valley

On September 6, 2018, the Company announced it entered into an agreement to acquire 100% of the ownership interests in Arlington Valley, LLC, which owns the Arlington Valley facility (Arlington facility), a 580 megawatt (MW) combined cycle natural gas generation facility, from funds managed by Oaktree Capital Management, L.P. and its co-investors. On November 30, 2018, the Company completed the acquisition of Arlington Valley for a total of $399 million (US$303 million), including preliminary working capital and other closing adjustments of $3 million (US$3 million). Capital Power financed the transaction using its credit facilities followed by permanent debt financing (see Subsequent Events).

The Arlington facility sells capacity and electricity to an investment grade load serving utility (credit ratings of A2/A- from Moody's and S&P, respectively) under tolling agreements through 2025. The Arlington facility is adjacent to the Palo Verde hub allowing for additional capacity and energy to be sold into the Desert Southwest (DSW) or the California Independent System Operator (CAISO) wholesale markets during the months outside the summer tolling months.

The acquisition of the Arlington facility supports the Company's U.S. growth strategy and fully meets the Company's investment criteria. The Arlington facility is a well-positioned asset in the attractive DSW power market with growing demand and a low investment risk environment. In addition to meeting the Company's expected return criteria, the investment contributes to the Company's dividend growth strategy through immediate adjusted funds from operations (AFFO) accretion supported by contracted cash flows to the end of 2025 with a high probability of re-contracting as confirmed through third-party market assessments.

The Arlington facility is expected to generate approximately US$62 million of adjusted EBITDA and US$44 million of AFFO in 2019 during the last year of its current toll. Subsequently, adjusted EBITDA averages US$35 million per year (ranging from US$32 million to US$38 million) and US$16 million of AFFO during the 6-year period from 2020 to 2025. Based on the expected financing, the 5-year average accretion for AFFO is expected to be $0.22 per share reflecting a 6% increase. The average accretion to earnings is expected to be $0.03 per share in the first 5 years, representing a 2% increase.

Dividend increase

On July 27, 2018, the Company's Board of Directors approved an increase of 7% in the annual dividend for holders of its common shares, from $1.67 per common share to $1.79 per common share. This increased common dividend commenced with the third quarter 2018 quarterly dividend payment on October 31, 2018 to shareholders of record at the close of business on September 28, 2018.

Genesee contracted physical natural gas capacity

During the second quarter of 2018, Capital Power secured additional physical natural gas delivery capacity for the Genesee site. This capacity is expected to enable increased natural gas co-firing as early as 2020 and allows for full conversion to natural gas as early as 2020.

Genesee royalty rate agreement

During the second quarter, Capital Power entered into an agreement with Genesee Royalty Limited Partnership establishing a fixed royalty rate structure in place of the previous structure which was based on coal regulations from the 1980's. The new structure provides improved royalty cost certainty in the future.

Investment in C2CNT

In May 2018, Capital Power acquired a 5% equity interest in C2CNT, a company that developed and is now testing at scale an innovative technology that captures and transforms carbon dioxide (CO_2) into a useful and high-value product called carbon nanotubes, for total consideration of $3.2 million (US$2.5 million). This technology will take CO_2 from many sources including emissions from thermal power generation and other industrial processes and convert it into a carbon-based product that can be used in various industries. This investment in C2CNT supports Capital Power's pursuit of innovative and leading-edge technology and approaches that have the potential to reduce greenhouse gases. Included with the acquisition is an option that may be elected prior to March 1, 2020 to increase the Company's equity interest in C2CNT by an additional 20%.

Bloom Wind tax equity agreement amendment

As part of the enactment of the U.S. Tax Cuts and Jobs Act of 2017 in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate (effective January 1, 2018), a change in tax law provision was triggered in the tax equity agreement for Bloom Wind. As a result, in May of 2018, the Company re-negotiated certain commercial terms within the tax equity agreement for Bloom Wind. The re-negotiated terms of the Bloom Wind tax equity agreement resulted in an interest rate increase on the tax equity financing balance. As well, a one-time reduction to the tax equity financing balance by $44 million (US$33 million) was recorded relating to additional tax benefits used by the tax equity partner. The overall impact of the re-negotiated terms of the tax-equity agreement resulted in a one-time, non-cash increase in net income after tax of $15 million (US$11 million). Under the re-negotiated tax equity agreement and considering the reduction in the U.S. Federal corporate tax rate, the Company has maintained its original expected returns for the project.

Completion of contracts for Cardinal Point Wind

On April 30, 2018, Capital Power announced that the construction of Cardinal Point Wind will proceed once all applicable regulatory approvals are received. Cardinal Point Wind is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020. Capital Power will operate Cardinal Point Wind under a 12-year fixed price contract with an investment grade U.S. financial institution covering 85% of the facility's output. 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. In addition, the Cardinal Point Wind project has secured 15-year, fixed-price Renewable Energy Credit (REC) contracts with three Illinois utilities. The REC and output contracts will secure long-term predictable revenues, allowing Cardinal Point Wind to secure renewable energy tax equity financing and provide Capital Power the opportunity to complete its third wind development project in the growing U.S. renewables market.

Executive appointment

Consistent with the Company's ongoing commitment to sustainability, during the second quarter of 2018, the Company named Senior Vice President, Kate Chisholm, its Chief Legal and Sustainability Officer, and sustainability was added to the Board of Directors' mandate.

SUBSEQUENT EVENTS

$300 million medium-term note issuance

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. The net proceeds of the offering will be used to repay indebtedness under the Company's credit facilities or for general corporate purposes.

Approval of normal course issuer bid

Subsequent to the end of 2018, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 9.0 million of its outstanding common shares during the one-year period from February 21, 2019 to February 20, 2020.

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	Supercritical coal-fired	2005	516	258	Merchant	-
Keephills 3	Supercritical coal-fired	2011	516	258	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	800	400	Merchant with tolling agreement for 50% of owned capacity plus additional 25% contracted for 2015 to 2017	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-fired steam turbine	1994	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
Genesee 2	Coal-fired steam turbine	1989	430	430	Capacity and output sold under Alberta PPA to Alberta Balancing Pool	2020
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 IESO	2032
East Windsor	Natural gas-fired cogeneration	2009	84	84	Energy supply contract with IESO	2029
K2 Wind [3]	Wind turbine	2015	270	90	PPA with IESO	2035
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	795	795	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 (APS)	2019 / 2025
Beaufort Solar, North Carolina	Solar	2015	15	15	PPA with Duke Energy Progress, LLC	2030
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 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 power purchase agreements or arrangements (PPAs).

[3] Capital Power's share of K2 Wind was disposed of effective December 31, 2018 (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.

			Capacity (MW)			
Facility category and facility	**Type of generating facility**	**Year to be commissioned**	**Facility**	**Capital Power interest**	**Revenues based on**	**Contract expiry**
Under construction or in advanced development						
Whitla Wind	Wind turbine	2019	202	202	Fixed price contract with the AESO	2039
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
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 Alberta market structure certainty and 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 the 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 2018 compared with 2017 are presented below followed by further discussion of these items.

(unaudited, $ millions)		
Consolidated net income for the year ended December 31, 2017		**134**
Increase (decrease) in adjusted EBITDA:		
Alberta commercial facilities and portfolio optimization	-	
Alberta contracted facilities	33	
Ontario and British Columbia contracted facilities	5	
U.S. contracted facilities	84	
Corporate	(1)	
Change in unrealized net gains or losses related to the fair value of commodity derivatives and emission credits	(26)	95
Decrease in impairments		83
Gain on disposal of joint venture (see Significant Events)		159
Increase in depreciation and amortization expense		(29)
Decrease in foreign exchange gain		(18)
Increase in finance expense and depreciation expense from joint ventures		(8)
Increase in net finance expense		(15)
Increase in income before tax		267
Change in income tax expense or recovery		(134)
Increase in net income		**133**
Consolidated net income for the year ended December 31, 2018		**267**

Results by facility category and other

	Year ended December 31							
	2018	2017	2018	2017	2018	2017	2018	2017
	Electricity generation (GWh) [1]		**Facility availability** (%) [2]		**Revenues and other income** (unaudited, $ millions)		**Adjusted EBITDA** (unaudited, $ millions) [3]	
Total electricity generation, average facility availability and facility revenues	20,229	17,194	95	96	1,199	829		
Alberta commercial facilities [4]								
Genesee 3	1,814	1,993	92	99	88	42		
Keephills 3	1,831	1,606	98	86	93	35		
Clover Bar Energy Centre 1, 2 and 3	860	292	89	94	59	10		
Joffre	609	325	95	97	53	19		
Shepard Energy Centre	2,938	2,633	92	97	136	98		
Halkirk	450	504	97	95	41	35		
Clover Bar Landfill Gas	-	19	21	82	-	2		
Alberta commercial facilities	8,502	7,372	93	95	470	241		
Portfolio optimization	N/A	N/A	N/A	N/A	117	416		
	8,502	7,372	93	95	587	657	228	228
Alberta contracted facilities [4]								
Genesee 1	3,268	3,112	100	92				
Genesee 2	2,959	3,323	94	98				
	6,227	6,435	97	95	268	241	203	170
Ontario and British Columbia contracted facilities								
Island Generation	27	15	100	100	39	39		
York Energy [5]	10	8	98	100	N/A	N/A		
East Windsor [6]	9	4	99	98	35	25		
K2 Wind [7]	222	193	99	99	3	N/A		
Kingsbridge 1	103	109	98	97	5	6		
Port Dover and Nanticoke	299	287	98	97	36	36		
Quality Wind	362	380	96	95	36	38		
EnPower [8]	38	22	96	96	3	2		
	1,070	1,018	98	98	157	146	170	165
U.S. contracted facilities								
Roxboro, North Carolina	327	333	96	98	37	37		
Southport, North Carolina	439	428	92	93	61	61		
Decatur Energy, Alabama [9]	2,703	1,074	95	95	88	46		
Arlington Valley, Arizona [10]	87	N/A	94	N/A	7	N/A		
Beaufort Solar, North Carolina	27	27	96	95	2	2		
Bloom Wind, Kansas [11]	711	381	98	98	94	39		
Macho Springs, New Mexico	127	126	98	98	15	16		
New Frontier, North Dakota [12]	9	N/A	98	N/A	-	N/A		
	4,430	2,369	95	96	304	201	176	92
Corporate [13]					58	63	(64)	(63)
Unrealized changes in fair value of commodity derivatives and emission credits					20	(162)	(67)	(41)
Consolidated revenues and other income and adjusted EBITDA					**1,394**	**1,146**	**646**	**551**

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 Management has determined, based on a review of the nature of future cash flows, that its Alberta assets should be combined as one 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.

5 York Energy was acquired on April 13, 2017. 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 $30 million for 2018, compared with $21 million for 2017. The facility's revenues are not included in the above results.

6 East Windsor was acquired on April 13, 2017.

7 K2 Wind 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 $33 million for 2018, compared with $45 million for 2017. The facility's revenues are not included in the above results, with the exception of $3 million of distribution income recorded in the fourth quarter of 2018, after K2 Wind was classified as an asset held for sale and equity accounting for the investment ceased. Capital Power's share of K2 Wind was disposed of effective December 31, 2018 (see Significant Events).

8 EnPower was acquired on June 1, 2017.

9 Decatur Energy was acquired on June 13, 2017.

10 Arlington Valley was acquired on November 30, 2018 (see Significant Events).

11 Bloom Wind was commissioned on June 1, 2017.

12 New Frontier Wind was commissioned on December 21, 2018 (see Significant Events).

13 Corporate revenues were offset by interplant category eliminations.

Energy prices and hedged positions

		Year ended December 31	
Alberta	**Unit**	**2018**	**2017**
Hedged position [1]	Percentage sold forward at beginning of year (%)	87	100
Spot power price average	$/MWh	50	22
Realized power price [2]	$/MWh	51	51
Natural gas price (AECO) [3]	$/gigajoule (Gj)	1.46	2.03

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 $50 per MWh in 2018, compared to $22 per MWh in 2017. The increase in spot prices in 2018 reflected increased demand, coal-plant retirements as well as the impact of higher carbon prices. Spot prices in 2017 reflected minimal market volatility combined with conservative offer strategies from market participants, stable coal supply, strong imports, fewer unplanned baseload facility outages and low natural gas prices.

Generation for the year ended December 31, 2018 was higher than 2017 primarily due to higher dispatch at Shepard, Joffre and Clover Bar Energy Centre. Availability for the year ended December 31, 2018 was lower compared to 2017 primarily due to planned outages at Shepard, Joffre, Clover Bar Energy Centre and Genesee 3 in 2018 compared to a planned outage at Keephills 3 in 2017.

Revenues and other income were lower for the year ended December 31, 2018 compared to 2017. This decrease is primarily due to lower realized revenues on portfolio optimization activities, partially offset by higher revenues earned at Alberta Commercial facilities from both increased generation as well as higher spot prices.

Adjusted EBITDA for the year ended December 31, 2018 was comparable to 2017. Increases resulting from higher generation, higher ancillary services revenues, and higher margins earned on sales of emission credits during 2018 were offset by higher carbon costs, lower realized gains on portfolio optimization activities and increased maintenance expenses due to planned outages at various facilities in 2018.

Alberta contracted facilities

Availability for 2018 was higher compared with 2017 primarily due to fewer outages in 2018. Lower generation was due to lower dispatch by the PPA Buyer during 2018 as compared to 2017. Higher revenues and other income in 2018 compared with 2017 reflected the impact of higher Alberta power prices, including higher net availability incentive and excess energy payments received, and higher capacity revenues primarily due to higher PPA input rates.

Adjusted EBITDA was higher in 2018 compared with 2017, primarily due to the noted favourable revenues and other income variances. Adjusted EBITDA also reflected favourable variances for environmental compliance incentive recoveries and net savings due to increased natural gas supplementing and lower fuel usage as a result of the aforementioned lower dispatch.

Ontario and British Columbia contracted facilities

Generation was higher in 2018 compared with 2017 primarily due to higher wind capacity and generation at Port Dover and Nanticoke and K2 Wind, partially offset by lower wind capacity and generation at Quality Wind. Generation was also higher driven by the acquisitions in the second quarter of 2017 and higher dispatch at Island Generation. Revenues and other income were higher in 2018 compared with 2017 primarily due to the acquisitions of facilities in the second quarter of 2017. Adjusted EBITDA in 2018 was higher when compared with 2017 primarily due to the aforementioned variances in revenues including the cost variances resulting from the acquisitions in the second quarter of 2017. Revenues and other income does 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, revenues and other income and adjusted EBITDA were higher in 2018 compared with 2017 primarily due to the addition of Decatur Energy in June 2017, the commencement of commercial operations of Bloom Wind in June 2017 and the impacts of the updated Bloom tax equity investor agreement signed during the second quarter of 2018. The acquisition of Arlington Valley (see Significant Events) in the fourth quarter of 2018 also contributed slightly to higher 2018 revenues and other income and generation. Availability in 2018 was comparable to 2017.

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.

Net corporate expenditures for 2018 were generally consistent with 2017 primarily due to the provisions recorded in 2017 for the Line Loss Rule Proceeding and higher business development expenses resulting from the Veresen thermal facilities and Decatur Energy acquisitions in the second quarter of 2017, largely offset by higher performance incentive expenses due to the increase in the Company's share price and company performance during the 2018 year.

Unrealized changes in fair value of commodity derivatives and emission credits

(unaudited, $ millions)	Year ended December 31			
	2018	2017	2018	2017
Unrealized changes in fair value of commodity derivatives and emission credits	**Revenues and other income**		**Adjusted EBITDA**	
Unrealized gains (losses) on Alberta power derivatives	79	(192)	(5)	(30)
Unrealized (losses) gains on U.S. energy derivatives	(51)	3	(51)	3
Unrealized (losses) gains on natural gas derivatives	(10)	19	(16)	(15)
Unrealized gains on emission derivatives	2	8	2	8
Unrealized gains (losses) on emission credits held for trading	-	-	3	(7)
	20	**(162)**	**(67)**	**(41)**

The Company's financial results relating to its Alberta commercial facilities and portfolio optimization include unrealized changes in the fair value of commodity and other derivatives.

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

Unrealized losses on the Alberta power portfolio of $5 million recognized by the Company in 2018 were 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 comparable period in 2017, the Alberta power portfolio recognized unrealized losses of $30 million primarily due to the reversal of prior period unrealized gains on net forward sales contracts that settled during the period as well as the impact of increasing forward prices on net forward sales contracts.

During the year-ended December 31, 2018, the Company recorded unrealized losses of $51 million on U.S. energy derivatives, due 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. During the comparable period in 2017, unrealized gains on U.S. energy derivatives of $3 million were attributable to the power swap contracts for New Frontier Wind and Bloom Wind generation.

Unrealized losses on natural gas derivatives of $16 million recognized in 2018 were due to 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. During the comparable period in 2017, unrealized losses of $15 million reflected the impact of decreasing forward natural gas prices on net forward purchase contracts as well as the reversal of prior periods' unrealized gains on positions that settled during the year.

Unrealized gains on emission derivatives of $2 million recognized by the Company in 2018 were primarily due to forward purchase contracts on emissions allowances and RECs which were valued against increasing forward prices partially offset by the reversal of previously unrealized gains on positions that settled during the year. During the comparable period in 2017, unrealized gains on emission derivatives of $8 million were primarily due to net forward purchase contracts on emissions allowances and RECs which were valued against increasing forward prices and the impact of the reversal of previously unrealized losses on positions that settled during the period.

Unrealized gains on emission credits held for trading of $3 million recognized in 2018 were primarily due to the fair value adjustment on credits transferred to held for trading during the year, and the reversal of prior period unrealized losses on emission credits sold in 2018. During 2017, unrealized losses of $7 million were recognized, primarily due to the reversal of prior periods' unrealized gains on emission credits sold during the year.

Consolidated other expenses and non-controlling interests

(unaudited, $ millions)	Year ended December 31	
	2018	2017
Interest on borrowings less capitalized interest	(110)	(99)
Other net finance expense – interest on coal compensation from the Province of Alberta, sundry interest, guarantee and other fees	11	12
	(99)	(87)
Other finance expense – amortization and accretion charges, including accretion of deferred revenue pertaining to coal compensation from the Province of Alberta	(24)	(21)
Total net finance expense	(123)	(108)
Impairments	-	(83)
Depreciation and amortization	(300)	(271)
Foreign exchange gain	10	28
Gain on disposal of joint venture (see Significant Events)	159	N/A
Finance expense and depreciation expense from joint ventures	(32)	(24)
Income tax (expense) recovery	(93)	41
Net loss attributable to non-controlling interests	7	10

Net finance expense

Net finance expense increased in 2018 compared with 2017 primarily due to additional loans and borrowings as a result of the acquisition of the Veresen thermal facilities and Decatur Energy and the receipt of Bloom Wind Project Investor financing in the second quarter of 2017. Further contributing to the increased finance expense was additional loans and borrowings as a result of the acquisition of Arlington Valley in the fourth quarter of 2018 (see Significant Events).

Impairments

During the third quarter of 2018, no impairment losses were recorded. In 2017, the Company recognized pre-tax impairment losses on the Southport, Roxboro and Decatur Energy cash generating units of $32 million, $14 million and $37 million, respectively.

Depreciation and amortization

Depreciation and amortization for the year ended December 31, 2018 increased compared with the prior year primarily due to the facilities acquired in the second quarter of 2017 and the Arlington Valley acquisition in the fourth quarter of 2018 (see Significant Events).

Foreign exchange gain

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.

In June 2017, the Company increased its committed credit facilities by US$300 million to fund the acquisition of Decatur Energy which was an addition to its pre-existing outstanding U.S. dollar denominated debt payable of US$295 million. Approximately US$300 million was economically hedged using foreign currency derivative instruments. In September 2017, the Company issued $450 million of medium-term notes which were primarily used to repay the increased committed credit facilities. The foreign exchange gain consisted primarily of the gain incurred on the revaluation of U.S. dollar denominated debt not economically hedged. For 2017, the exchange rate of the Canadian dollar relative to the U.S. dollar strengthened resulting in an unrealized gain.

Gain on disposal of joint venture

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 (see Significant Events).

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 K2 Wind and York Energy, 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 (expense) recovery

In 2018, the Company recorded an income tax expense compared with an income tax recovery in 2017. The change is primarily due to the disposal of interest in the K2 Wind joint venture in the fourth quarter of 2018, amounts attributable to tax-equity interests, and, in the second quarter of 2017, there was a reversal of a previous non-cash write-down related to U.S. income tax losses that resulted in tax recovery of $86 million, of which no comparable tax recovery was recognized in 2018. These changes are partially offset by deferred tax expense of $31 million recognized as part of the enactment of the U.S. Tax Cuts and Jobs Act in the fourth quarter of 2017, and the resulting reduction in the U.S. Federal corporate tax rate, of which no comparable tax expense was recognized in 2018.

Non-controlling interests

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

COMPREHENSIVE INCOME

(unaudited, $ millions)	Year ended December 31	
	2018	**2017**
Net income	267	134
Other comprehensive income (loss):		
Net unrealized gains (losses) on derivative instruments designated as cash flow hedges	15	(4)
Net unrealized gains on derivative instruments designated as cash flow hedges – joint ventures	3	3
Net realized losses (gains) on derivative instruments designated as cash flow hedges reclassified to net income	14	(63)
Net realized losses on derivative instruments designated as cash flow hedges reclassified to net income – joint ventures	2	3
Unrealized foreign exchange gain (loss) on the translation of foreign operations	50	(53)
Actuarial gain (loss) related to the company's defined benefit pension plan	2	(1)
Losses realized in net income on disposal of joint venture (see Significant Events)	12	-
Total other comprehensive income (loss), net of tax	98	(115)
Comprehensive income	**365**	**19**

Other comprehensive income (loss) 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, 2017 to December 31, 2018 were as follows:

(unaudited, $ millions)	As at December 31					
	2018	**2017**	**Increase (decrease)**	**Acquisitions through business combinations**	**Other**	**Primary other changes**
Trade and other receivables	462	278	184	-	184	Primarily due to the receivable for a portion of the proceeds on disposal of K2 Wind (see Significant Events), higher receivables at various facilities due to higher pool prices and receivables from counterparties relating to facility emissions compliance obligations.
Inventories	200	120	80	7	73	Increase in emission credits held for trading, including transfers from intangible assets, and higher coal inventory.
Finance lease receivables	620	644	(24)	-	(24)	Reduction in net investment in finance leases due to the recognition of accounting minimum lease payments partially offset by unearned finance income.
Government grant receivable	459	493	(34)	-	(34)	Decrease due to the receipt of the 2018 payment related to the phase out of coal-fired generation, net of accrued interest on the receivable balance.
Net derivative financial instruments (liabilities) assets	(45)	29	(74)	-	(74)	Decrease mainly due to a combination of increases in unrealized losses recorded for Cardinal Point Wind, New Frontier Wind and Bloom Wind swaps and settlement of FX hedges.
Equity-accounted investments	142	184	(42)	-	(42)	Distributions received and the disposal of the Company's interest in the K2 Wind joint venture (see Significant Events), partially offset by net income and unrealized gain recognized through other comprehensive income.
Intangible assets	473	401	72	113	(41)	Decrease primarily due to emission credits returned and used for compliance and emission credits transferred to inventories, partially offset by increases for costs on projects under development.
Property, plant and equipment	4,803	4,378	425	296	129	Increase mainly due to capital additions, primarily New Frontier Wind, offset partially by depreciation.

(unaudited, $ millions)	As at December 2018	As at December 2017	Increase (decrease)	Acquisitions through business combinations	Other	Primary other changes
Trade and other payables	245	216	29	4	25	Increase is primarily due to New Frontier construction resulting in higher accounts payable balances.
Loans and borrowings (including current portion)	2,647	2,146	501	-	501	Addition of debt related to New Frontier Wind and Arlington Valley (see Significant Events).
Net deferred tax liabilities	376	300	76	-	76	Increase primarily attributable to taxable temporary differences, mainly PPE, that will reverse in the future, tax-equity interests (see Significant Events), and the recognition of a deferred tax liability arising on the disposal of the Company's interest in the K2 Wind joint venture.
Provisions (including current portion)	345	302	43	11	32	Increase due to increased long-term incentive provisions driven by the increase in share price, higher short-term incentive in the current year driven by favourable results, increase in the Genesee Mine decommissioning provision, and recording of the New Frontier Wind decommissioning provision (see Contractual Obligations, Contingent Liabilities and Provisions).
Share capital	3,200	3,262	(62)	-	(62)	Decrease primarily due to common shares purchased.
Deficit	(156)	(181)	25	-	25	Net income less common and preferred share dividends and opening adjustments from change in accounting policy (see Accounting Changes).
Other reserves	32	(67)	99	-	99	Unrealized gains on foreign exchange translation, unrealized gains on cash flow hedges, reclassification of losses on cash flow hedges to net income and losses realized in net income on disposal of interest in K2 Wind joint venture (see Significant Events).

LIQUIDITY AND CAPITAL RESOURCES

(unaudited, $ millions)	Year ended December 31		
Cash inflows (outflows)	**2018**	**2017**	**Change**
Operating activities	450	372	78
Investing activities	(554)	(1,114)	560
Financing activities	233	697	(464)

Operating activities

Cash flows from operating activities increased compared with 2017 due to higher EBITDA (before non-cash items, including unrealized changes in fair value of commodity derivatives and emission credits and non-cash tax equity attributes), partially offset by higher interest paid due to additional loans and borrowings as a result of the acquisition of the thermal facilities in 2017. Cash inflows in 2018 were also higher compared with 2017 due to positive 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.

Investing activities

Cash flows used in investing activities for the year ended December 31, 2018 decreased compared with the same period in 2017 primarily due to the acquisition of the thermal facilities and Decatur Energy in 2017, prepayment related to the amended Genesee Mine Joint Venture Agreement in 2017 and proceeds on disposal of the K2 Wind joint venture (see Significant Events) in 2018. Partially offsetting the decrease in cash flows used in investing activities was the acquisition of Arlington Valley (see Significant Events) in 2018 and higher spending on wind development projects related to New Frontier Wind (see Significant Events) and Whitla Wind in 2018 as compared to Bloom Wind spending in 2017.

Capital expenditures and investments

(unaudited, $ millions)	Pre-2017 Actual	Year ended December 31 2017 Actual	2018 Actual	2019 Estimated [1,2]	Actual or Projected Total [2]	Timing
Bloom Wind	219	95	-	-	314	Completed in June 2017
Genesee 4 & 5 [3,4]	16	2	-	-	700	Targeted completion as early as 2022
New Frontier Wind [5]	-	20	154	6	180	Completed in December 2018
Whitla Wind [6]	-	3	68	249	320	Targeted completion in the fourth quarter of 2019
Cardinal Point Wind [7]	-	2	26	243	295	Targeted completion in Q1 2020
Development sites and projects	-	9	6	1		
Subtotal growth projects		**131**	**254**	**499**		
Sustaining – plant maintenance excluding Genesee mine		54	84			
Sustaining – Genesee mine maintenance and lands		19	14			
Total capital expenditures [8]		**204**	**352**			
Emission credits held for compliance		20	5			
Investment in C2CNT [9] (see Significant Events)		-	3			
Capitalized interest		(6)	(5)			
Purchase of property, plant and equipment and other assets		**218**	**355**			

1 The Company's 2018 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, and Cardinal Point Wind 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 sufficient Alberta market certainty exists and new generation is required in Alberta to balance supply and demand.

[5] Projected total cost excludes a $19 million (US$15 million) developer fee paid to a subsidiary of the Company.

[6] The projected total cost for Whitla Wind reflects the midpoint of the expected range of construction costs of $315 million to $325 million.

[7] The projected total cost for Cardinal Point Wind reflects the midpoint of the expected range of construction costs of $289 million to $301 million (US$236 million to US$246 million).

[8] 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.

[9] In the second quarter of 2018, the Company acquired a 5% equity interest in C2CNT (see Significant Events) for total consideration of $3.2 million (US$2.5 million) to be paid over a two-year period. The initial payment of $1.3 million (US$1.0 million) was paid in the second quarter of 2018 and the balance of consideration will be paid by January 1, 2020.

Financing activities

The cash flows from financing activities for the year ended December 31, 2018 primarily reflected the net issuance of loans and borrowings in the year and a realized foreign exchange gain on the settlement of foreign currency derivative instruments pertaining to U.S. dollar borrowings, offset partially by the repayment of loans and borrowings, payment of common and preferred share dividends, and common shares purchased under the Company's normal course issuer bid. Cash flows from financing activities for 2018 decreased compared with 2017 most notably due to higher issuances of loans and borrowings and shares in 2017 driven by higher business acquisition activity as well as the receipt of Project Investor financing for Bloom Wind in 2017, partially offset by funding received from New Frontier Wind (see Significant Events) in 2018.

The Company's credit facilities consisted of:

(unaudited, $ millions)		**As at December 31, 2018**			**As at December 31, 2017**		
	Maturity timing	**Total facilities**	**Credit facility utilization**	**Available**	**Total facilities**	**Credit facility utilization**	**Available**
Committed credit facilities	2019/2023	1,150			1,055		
Letters of credit outstanding			99			30	
Bankers' acceptances outstanding			396			-	
Bank loans outstanding [1]			218			28	
		1,150	713	437	1,055	58	997
Bilateral demand credit facilities	N/A	200			200		
Letters of credit outstanding			172			139	
		200	172	28	200	139	61
Demand credit facilities	N/A	25	-	25	25	-	25
		1,375	**885**	**490**	**1,280**	**197**	**1,083**

1 U.S. dollar denominated bank loans outstanding totaling US$160 million (December 31, 2017 – US$23 million).

As at December 31, 2018, the committed credit facility utilization increased $655 million compared with the utilization as at December 31, 2017, due to the issuance of bankers' acceptances, increased U.S. dollar bank loans, and increased letters of credit outstanding. In the second quarter of 2018, the existing credit facilities were reduced in size by $55 million, to $1 billion, and the maturities were extended to July 2023. In the fourth quarter of 2018 the Company secured a committed non-revolving $150 million credit facility for a period of up to 12 months, or December 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, 2018
Modified consolidated net tangible assets to consolidated net tangible assets ratio [1]	Not less than 0.80 to 1.0	0.88
Consolidated senior debt to consolidated capitalization ratio [1]	Not more than 0.65 to 1.0	0.49
Consolidated EBITDA to consolidated interest expense [1, 2]	Not less than 2.5 to 1.0	3.6

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 2019 include:

(unaudited, $ millions)	2019 Expected Cash Requirements
Repayment of debt payable	419
Capital expenditures – sustaining	85
Capital expenditures – ongoing growth projects	499
Capital expenditures – Genesee performance standard	13
Common share dividends [1]	190
Preferred share dividends	43

1 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

The Company has off-statement of financial position arrangements including operating leases and, as at December 31, 2018, $271 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	
	2018	2017
Loans and borrowings	2,647	2,146
Finance lease obligation [1]	18	18
Less cash and cash equivalents	(182)	(52)
Net debt	2,483	2,112
Share capital	3,200	3,262
Deficit and other reserves	(124)	(248)
Non-controlling interests	43	48
Total equity	3,119	3,062
Total capital	**5,602**	**5,174**

1 Includes the current portion disclosed within trade and other payables.

CONTRACTUAL OBLIGATIONS, CONTINGENT LIABILITIES, OTHER LEGAL MATTERS AND PROVISIONS

(unaudited, $ millions)	Payments due by period						
	2019	2020	2021	2022	2023	Thereafter	Total
Loans and borrowings [1]	419	320	329	18	481	817	2,384
Interest on loans and borrowings	106	94	69	60	49	75	453
Finance lease obligations	1	1	1	1	1	13	18
Capital – growth projects [2]	499	24	-	-	-	-	523
Decommissioning provisions [3]	6	5	6	37	7	360	421
Energy purchase and transportation contracts [4]	48	25	24	27	27	490	641
Operating and maintenance contracts	37	47	55	42	23	205	409
Operating leases	11	11	9	8	9	94	142
Environmental credits [5]	28	7	-	3	4	9	51
Commodity and other derivative liabilities net of financial assets	12	4	6	5	3	70	100
Total	**1,167**	**538**	**499**	**201**	**604**	**2,133**	**5,142**

1 Repayments of loans and borrowings exclude fair value differentials of $17 million related to debt assumed on previous asset acquisitions and $267 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

2 Capital Power's obligations for capital – growth projects in future periods include Cardinal Point Wind in 2019 and 2020 and Whitla Wind and expected spend on other development sites and projects in 2019. These obligations exclude interest to fund construction and refundable transmission system contribution payments.

3 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.

4 Energy purchase and transportation contracts include natural gas transportation contracts which are based on estimates subject to changes in regulated rates for transportation and natural gas purchase contracts which are based on estimates subject to changes in expected consumption levels, and have expiry terms ranging from 2019 to 2035.

5 Future environmental credits purchases are presented net of future environmental credits sales.

Contingent liabilities

North Carolina facility permitting

The North Carolina Department of Air Quality (DAQ) has indicated that new permits will be required for the Company's Roxboro and Southport facilities based on 2015 carbon monoxide and particulate matter emissions. The required permits have been applied for, however the DAQ advised in June 2017 that it is also pursuing permits for sulfur dioxide emissions. It is unknown at this time what, if any, new capital investment may be required under these permits.

Other 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 and 2018, 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 (but not including) 2017.

The Company is participating in appeal processes rendering the final outcome of the LLR Proceeding still unknown. However, based on the current decision, Capital Power would incur additional charges related to transmission amounts of historical periods and as such recorded a current provision of $9 million during the fourth quarter of 2017 pertaining to the estimated net liability for its currently held Alberta assets.

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 quarterly 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. The ERM Program aligns with the International Organization for Standardization's standard for risk management, ISO 31000, and the Company's approach is to undertake risk assessment in conjunction with core corporate 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 (CEO) has ultimate accountability for managing the Company's risks and approves the framework for enterprise risk management. The President and CEO 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 Risk Oversight Council (consisting of the senior management representatives appointed by the President and CEO) establishes the overall direction, structure, conduct and control of Capital Power's commodity exposure management activities, both in physical and financial derivatives markets. 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 (TCFD). 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/CCD.

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.

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 other 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 changes in the legislative and regulatory environment or their impact on the Company's business, income tax status, operations, or the markets in which the Company operates.

In the fourth quarter of 2016, the Government of Alberta announced it would transition the province's electricity market structure from energy-only to capacity by 2021. The AESO was directed by the Government of Alberta to design the market structure and accompanying rules. The AESO has completed consultations associated with this directive and is expected to submit its rule package to the Alberta Utilities Commission for approval in the first quarter of 2019.

The Canadian federal government announced in the fourth quarter of 2016, 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 2030, and the opportunity to extend the life of coal units through conversion to natural gas. In December 2018, the Government of Canada released further details on the development and implementation of their federal Output-Based Pricing System (OBPS). The OBPS will be applied to provinces and territories without their own equivalent program in January 2019 (Ontario, Manitoba, New Brunswick, Prince Edward Island, and Saskatchewan). Amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (CST) were finalized in December 2018, which mandate coal phase out on December 31, 2029. Changes to the Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation were also finalized in December 2018 and set the GHG emission requirements for coal units converted to natural gas (CTG units). These regulations will impact the useful lives of the Company's current coal assets, commencing in 2019, as described within Use of Judgments and Estimates. As expected, in Q1 of 2018, the Government of Alberta set final policy regarding NO_x emissions from CTG units. According to the policy, converted

Genesee 1 and 2 NO_x emissions would have to be limited to 50% of their 2003 baseline NO_x emissions, while Genesee 3 and Keephills 3 would not have to reduce their current approved NO_x emissions.

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 birds and bats 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.

Capital Power's operations are complex and the determination of income taxes involves income tax interpretations, regulations and legislation that are continually changing. Future changes in tax legislation may have an adverse impact on Capital Power, its shareholders and the value of the Company's common shares.

Strategies employed for managing legal, regulatory and stakeholder risk:

- 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 with corrective actions as necessary.
- Establish positive relationships with all levels of government and stakeholders.
- Consult with all levels of government with respect to policy development and current and proposed legislation.
- 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.
- 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.

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.

Commodity price volatility 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 50% interests in Genesee 3 and Keephills 3 are not covered by long-term commercial contracts, the units are baseload coal-fired generating plants with relatively low variable costs and generally run when they are available. For the Company's Genesee 3, Keephills 3, Clover Bar Energy Centre, Shepard and Joffre plants, spot electricity prices, the plants' variable costs, and planned and unplanned outages affect profitability.

Capital Power uses derivative instruments, including futures, forwards, options and swaps, to manage its commodity 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 commodity-based contracts in the natural gas and electricity markets for 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 commodities.

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 commodity price volatility risk:

- Execute 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.
- 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.

Operation and maintenance of equipment and systems 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 provide service.

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.

Capital Power employs several key computer application systems to support its operations, such as electricity facility control, energy trading risk management, and enterprise resource planning systems. Failure of any of these systems, during or after implementation, could result in significant lost revenues, increased costs or regulatory fines. Capital Power is also susceptible to the external risk of cyber-attacks, including unauthorized access to and/or penetration of its computer networks and applications.

Strategies employed for managing operation and maintenance of equipment and systems 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.
- Minimize the customization of commercial software, monitor the impacts on processes and internal controls and undertake remedial actions, as required.
- Ensure operations, sustainment and implementation projects are properly resourced with qualified and trained staff and contractors.
- Employ robust firewalls and access security protocols as well as detection systems that will identify or prevent unauthorized systems or devices.
- Stay current on all cybersecurity threats and maintain a robust security profile.
- Employ change management to ensure all enhancements are fully tested and approved, prior to production deployment.

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, expired December 25, 2018. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is reached. Negotiations related to a new collective agreement have commenced.

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 December 23, 2018. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is reached. Negotiations related to a new collective agreement are expected to begin in the first half of 2019.

The Company's collective agreement with IBEW 1007, which represents all employees directly engaged in the maintenance of the electrical generation at Genesee, expired December 22, 2018. All existing terms, conditions and wage rates in the expired collective agreement will continue in force and effect until a new collective agreement is concluded. Negotiations related to a new collective agreement are expected to begin in the first quarter of 2019.

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, during January 2019, has filed for bankruptcy and subsequently had its credit rating downgraded to “D”, representing default. PG&E is in the midst of political and regulatory pressure as well as uncertainty resulting from claims against them related to wildfires that occurred in 2017 and 2018. 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, cyber-attacks on our key information technology systems to support our core operations, 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 monitoring and surveillance of the Company's information technology systems.
- Regular communication with external governmental and industry groups to share threat intelligence, trend analysis, and best practices.
- Periodic audits of the effectiveness of the Company's information technology security systems.

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 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.

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.

Energy supply 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 operation. The price of fuel supplies is dependent upon a number of factors, including: (i) the supply and demand for such fuel supplies, (ii) the quality of the fuel, and (iii) the cost of transporting such fuel supplies to Capital Power's facilities. 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.

Coal for the Genesee and Keephills 3 plants 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 and the prevailing electricity market 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. Decatur Energy, East Windsor and York Energy operate under long-term PPAs with fuel cost flow-through provisions. 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'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 energy supply 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.
- Actively participate on the Genesee Coal Mine Joint Venture Committee and exercise contractual rights as required.
- 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.

Tax compliance risk

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 for 2018 and 2017 were 27%. 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 compliance risk:

- 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 tax equity debt financing to finance U.S. developments.

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. The Company is exposed to risks associated with weather, legal and arbitration proceedings, and risks that are not fully covered by various insurance policies.

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, 2018, the Company loaned $1,896 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 $259 million as at December 31, 2018 ($228 million as at December 31, 2017) 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 is obligated to purchase environmental credits totaling $350 million in future years. Offsetting these purchase obligations are future sales obligations totaling $299 million. The Company expects to use a majority of the net credits purchased to comply with applicable environmental regulations

REGULATORY MATTERS

The Ontario Independent Electricity System Operator (IESO) is in the preliminary stages of a Market Renewal Program (MRP), which is a series of coordinated initiatives expected to result in a fundamental redesign of Ontario's electricity market. The IESO's stated goal for the MRP is to improve how electricity is priced, scheduled and procured to meet Ontario's electricity system needs. The Company is actively participating in the MRP stakeholder process and collaborating with the IESO. The PPAs for the York Energy, East Windsor, Port Dover and Nanticoke and Kingsbridge 1 facilities contain provisions for renegotiation should there be a change in market rules. The intent of these provisions is to preserve the underlying supplier economics within the respective PPAs. Accordingly, the Company does not believe that implementation of the MRP will have a material adverse effect on its financial condition and results of operations.

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 Government has proposed legislation that will impose a carbon pricing system on provinces that do not have an equivalent system in place to meet targeted GHG reduction levels, that if implemented is proposed to be in place effective retroactive to January 1, 2019. The PPAs for York Energy and East Windsor both 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 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.	The Company tested its East Windsor CGU for impairment during the third quarter of 2018. The carrying amount of the East Windsor CGU was below the high-end of the respective range of its estimated recoverable amount and as such, no impairment was required.
Whether an arrangement contains a lease and classification of leases	Whether a PPA or similar contract conveys the right to use the Company's property, plant and equipment in return for payment, and, if so, a lease exists. Whether substantially all the risks and rewards of ownership of property are transferred to determine if the lease is accounted for as a finance lease or, if not, the lease is accounted for as an operating lease.	Contracts that convey the right to use Capital Power's property, plant and equipment and, therefore, contain a lease: 1. **Finance leases as the lessor** (substantially all the risks and rewards are transferred) • Kingsbridge 1 energy supply contract • Port Dover and Nanticoke energy supply contract • Quality Wind electricity purchase agreement 2. **Operating leases as the lessor** (substantially all the risks and rewards remain with Capital Power) • Genesee 1 and 2 PPA • Island Generation PPA • Roxboro PPA • Decatur Energy tolling agreement • Arlington Valley tolling agreement • EnPower EPA • East Windsor energy supply contract 3. **Finance lease as the lessee** (substantially all the risks and rewards remain with Capital Power) • Beaufort Solar sale and leaseback agreement
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 Wind 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.	K2 Wind (prior to disposal, see Significant Events) and York Energy are accounted for as joint ventures because each of the partners effectively has rights to the net assets of the arrangement. Genesee 3, Keephills 3, 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-2030. As a result of the Amendments to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations (CST), and the changes to Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation, commencing in 2019, Capital Power will be prospectively adjusting the useful lives of its current coal assets to reflect these new expected end of life dates. This will include adjusting the lives of asset components that could be used in a coal-to-gas (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.
Revenue recognition	The value of electricity and natural gas consumed by customers but not billed until after year-end is based on data provided by the parties delivering the commodity.

ACCOUNTING CHANGES

Effective January 1, 2018

The Company adopted new accounting standards as issued by the International Accounting Standards Board (IASB). The standards and impact to Capital Power are:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
Revenue from contracts with customers (IFRS 15)	New standard on revenue recognition consisting of a single and comprehensive framework for revenue recognition to ensure consistent	The Company applied IFRS 15 using the cumulative effect method recognizing the cumulative impact of initially applying IFRS 15 as an adjustment to the opening balance of equity at January 1, 2018. The adoption of this standard has resulted in a pre-tax increase to the opening deficit of $44 million which consists of:	Effective for annual periods beginning on or after January 1, 2018.

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
	treatment for all transactions in all industries and capital markets.	• Increase to opening deficit of $3 million ($2 million post tax) and a decrease to emission revenue receivables due to the timing of revenue recognition of RECs. Prior to the adoption of IFRS 15, the Company recognized revenue on the sale of RECs at the time of generation. Under IFRS 15, the Company satisfies its performance obligation when RECs are delivered to the customer which occurs subsequent to the period of REC generation. • Increase to opening deficit of $41 million ($31 million post tax) and increased deferred revenue and other liabilities for a contract liability due to the timing of revenue recognition for capacity revenue related to the Company's interest in the Joffre joint operation. Prior to the adoption of IFRS 15, revenue was recognized when the Company had the right to bill. Capacity payments are based on a declining rate base capacity payment schedule. Under IFRS 15, the performance obligation is satisfied as the facility provides the availability of the contracted power generation and as such, revenue is recognized over the term of the contract. The Company applied the "right to invoice" practical expedient on energy revenues where the Company has a right to consideration from a buyer that corresponds directly with the value to the buyer of the Company's performance obligation completed to date. A number of the Company's revenue contracts are accounted for under IAS 17 – Leases and IFRS 9 – Financial Instruments and therefore are excluded from the scope of IFRS 15. Additional disclosures included in the consolidated financial statements include disaggregated revenues by major types and current operational groupings of revenues.	
Financial instruments (IFRS 9)	New standard, replacing IAS 39, which addresses requirements for classification and measurement, impairment, hedge accounting and de-recognition of financial assets and liabilities.	The change in accounting policy has been applied retrospectively and did not result in a change in the carrying amount of any financial instruments at the transition date. Additionally, the Company adopted consequential amendments to IFRS 7: Financial Instruments: Disclosures that have been applied commencing January 1, 2018. The Company completed an assessment of its financial assets and liabilities classification as at January 1, 2018 under IFRS 9. While the categories are different under the new standard, there were no changes to the accounting methods applied as compared to the previous classification under IAS 39. 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, 2018. Derivative instruments continue to be measured at fair value through income or loss unless cash flow hedge accounting is used, in which case they are measured at fair value through other comprehensive income. The Company has applied the new general hedge accounting model prospectively and determined no changes to its hedging relationships previously designated under IAS 39.	Effective for annual periods beginning on or after January 1, 2018.

Future

The IASB issued the following new standards and amendments to existing standards that were not yet effective as of December 31, 2018 and are relevant to Capital Power:

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
Leases (IFRS 16)	The new standard which replaces 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	The Company has 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 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	Effective for annual periods beginning on or after January 1, 2019.

Standard	Description	Impact to Capital Power and current implementation status	Effective Date
	under the new standard.	deficit balance. The Company will recognize a right-of-use asset for the underlying asset and a lease liability for future lease payments. Management has determined that certain PPAs and energy supply contracts that are currently considered to be finance leases with the Company as the lessor will no longer be considered leases upon adoption of this new 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 accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors and treated as a change in accounting policy. The Company is in the process of finalizing its transition to IFRS 16 and the expected adjustments to the consolidated statements of financial position as a result of the changes described above are summarized in the tables below.	

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

	Leases as the lessee			Leases as the lessor			
	IAS 17 (Old)	IFRS 16 (New)	Impact	IAS 17 (Old)	IFRS 16 (New)	Impact	Overall Impact
As at January 1, 2019							
Assets [1]	2	86	84	644	553	(91)	(7)
Liabilities [2]	4	94	90	-	(25)	(25)	65
Opening deficit adjustment [2]	-	(6)	(6)	-	(66)	(66)	(72)
As at January 1, 2018							
Assets [1]				667	588	(79)	(79)
Liabilities [2]				-	(22)	(22)	(22)
Opening deficit adjustment [2]				-	(57)	(57)	(57)

[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 increases to the opening deficit balances, net of estimated deferred tax impacts at a rate of 27%, which also impact the liabilities amounts as reductions to deferred tax liabilities.

The expected retrospective adjustments to the consolidated statement of income for the year ended December 31, 2018 pertaining to the leases where Capital Power is the lessor are:

	IAS 17 (Old)	IFRS 16 (New)	Impact
Revenues	(23)	-	23
Depreciation and amortization	-	(35)	(35)
Income tax (expense) recovery	6	9	3
Net income (loss)	(17)	(26)	(9)

FINANCIAL INSTRUMENTS

The classification, carrying amounts and fair values of financial instruments held at December 31, 2018 and 2017 were as follows:

(unaudited, $ millions)		December 31, 2018		December 31, 2017	
	Fair value hierarchy level [1]	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets:					
Amortized cost					
Cash and cash equivalents	N/A	182	182	52	52
Trade and other receivables [2]	N/A	385	385	200	200
Government grant receivable [3]	Level 2	511	505	544	544
Finance lease receivables [3]	Level 2	644	723	667	757
Fair value through income or loss					
Derivative financial instruments assets – current and non-current	See Below	148	148	157	157
Fair value through other comprehensive income					
Derivative financial instruments assets – current and non-current	See Below	11	11	14	14
Financial liabilities:					
Other financial liabilities					
Trade and other payables [4]	N/A	244	244	215	215
Finance lease obligation [3]	Level 2	18	18	18	18
Loans and borrowings [3]	Level 2	2,647	2,645	2,146	2,203
Fair value through income or loss					
Derivative financial instruments liabilities – current and non-current	See Below	186	186	112	112
Fair value through other comprehensive income					
Derivative financial instruments liabilities – current and non-current	See Below	18	18	30	30

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, finance lease receivables and other financial assets.

3 Includes current portion.

4 Excludes current portion of finance lease obligation.

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, 2018 and 2017 and used for risk management purposes were measured at fair value and consisted of the following:

(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)**

(unaudited, $ millions)		As at December 31, 2017			
	Fair value hierarchy level	**Commodity cash flow hedges**	**Commodity non-hedges**	**Foreign exchange non-hedges**	**Total**
Derivative financial instruments assets	Level 2	14	84	41	139
	Level 3	-	32	-	32
		14	116	41	171
Derivative financial instruments liabilities	Level 2	(30)	(101)	(9)	(140)
	Level 3	-	(2)	-	(2)
		(30)	(103)	(9)	(142)
Net derivative financial instruments (liabilities) assets		**(16)**	**13**	**32**	**29**

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 income (loss) and, when realized, are reclassified to net income as revenues, energy purchases and fuel, finance expense or foreign exchange gain/loss as appropriate.

As a result of the addition of Decatur Energy and the repayment of certain U.S. dollar denominated loans and borrowings during the third quarter of 2017, the foreign currency exposure that the cross-currency interest rate swap was hedging no longer existed. As a result, the Company de-designated the cross-currency interest rate swap as a foreign exchange cash flow hedge during the third quarter of 2017. Unrealized gains associated with this de-designated foreign exchange cash flow hedge began to flow directly through net income as foreign exchange gains starting in the third quarter of 2017. Prior to the time of de-designation of the foreign exchange cash flow hedge, the unrealized gains or losses were reclassified to net income, within foreign exchange gains or losses, each period to offset the impact to unrealized foreign exchange gains and losses from the revaluation of the U.S. dollar loans and borrowings that were being hedged.

The Company previously elected to apply hedge accounting on certain derivative financial instruments whereby the Company entered into swap agreements with third parties to swap the market revenues earned on Bloom Wind and New Frontier Wind generation for a fixed annual payment on Bloom Wind and a fixed price per MWh on New Frontier Wind. Since Bloom Wind's commercial operation date in June 2017, actual captured basis exceeded the expected basis differential and changes to the Bloom Wind Node price have not been as closely aligned to changes in the SPP North Hub price as previously expected. With this additional information, management revised the forward price methodology resulting in the Bloom Wind swap no longer meeting the hedge effectiveness criteria. Based on the revised methodology for Bloom Wind, management expects New Frontier Wind to function in a similar manner to Bloom Wind post commercial operation date. As a result, effective October 30, 2017, the Company de-designated the swap agreements relating to both Bloom Wind and New Frontier Wind as cash flow hedges. Since the forecasted transactions are still expected to occur, the fair value recognized in accumulated other comprehensive loss will remain and fair value adjustments subsequent to ineffectiveness will be recognized in net income. The balance in accumulated other comprehensive income will be reclassified to net income in future periods as generation occurs at the respective facilities.

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 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, 2018, 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, 2018, 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 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**
Total generation	5,406	5,213	4,584	5,026	4,839	4,720	3,673	3,962
Alberta commercial facilities								
Genesee 3	372	495	468	479	511	509	480	493
Keephills 3	483	494	434	420	362	380	419	445
Clover Bar Energy Centre 1, 2 and 3	264	217	204	175	92	140	24	36
Joffre	212	154	115	128	119	101	70	35
Shepard Energy Centre	769	789	585	795	694	730	560	649
Halkirk	130	85	103	132	168	95	119	122
Clover Bar Landfill Gas	-	-	-	-	2	6	6	5
	2,230	2,234	1,909	2,129	1,948	1,961	1,678	1,785
Alberta contracted facilities								
Genesee 1	877	829	751	811	860	830	576	846
Genesee 2	850	799	647	663	864	823	825	811
	1,727	1,628	1,398	1,474	1,724	1,653	1,401	1,657
Ontario and British Columbia contracted facilities								
Island Generation	-	17	-	10	3	12	-	-
York Energy	2	3	3	2	2	5	1	N/A
East Windsor	1	4	2	2	1	2	1	N/A
K2 Wind	70	35	41	76	57	28	29	79
Kingsbridge 1	33	14	20	36	37	11	25	36
Port Dover and Nanticoke	78	43	70	108	84	39	71	93
Quality Wind	112	74	98	78	117	85	84	94
EnPower	3	10	11	14	13	7	2	N/A
	299	200	245	326	314	189	213	302
U.S. contracted facilities								
Roxboro, North Carolina	74	87	90	76	86	80	88	79
Southport, North Carolina	106	104	118	111	120	124	92	92
Decatur Energy, Alabama	674	784	576	669	425	542	107	N/A
Arlington Valley, Arizona	87	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	5	8	8	6	6	7	8	6
Bloom Wind, Kansas	164	152	197	198	190	145	46	N/A
Macho Springs, New Mexico	31	16	43	37	26	19	40	41
New Frontier Wind, North Dakota	9	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	1,150	1,151	1,032	1,097	853	917	381	218

(%)	Three months ended							
Facility availability	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018	Dec 31 2017	Sep 30 2017	Jun 30 2017	Mar 31 2017
Total average facility availability	94	98	93	96	95	97	94	97
Alberta commercial facilities								
Genesee 3	74	98	98	97	100	100	97	99
Keephills 3	100	100	100	92	75	83	92	93
Clover Bar Energy Centre 1, 2 and 3	85	88	90	93	97	93	89	99
Joffre	100	97	90	93	100	100	96	92
Shepard Energy Centre	100	100	68	100	94	99	97	99
Halkirk	98	95	98	98	97	88	99	96
Clover Bar Landfill Gas	-	7	78	-	45	94	95	95
	93	96	87	96	93	95	95	97
Alberta contracted facilities								
Genesee 1	100	99	100	100	100	97	70	100
Genesee 2	98	100	93	83	100	96	100	97
	99	99	97	92	100	96	85	98
Ontario and British Columbia contracted facilities								
Island Generation	100	100	100	100	100	100	100	100
York Energy	100	100	94	100	100	100	100	N/A
East Windsor	99	99	99	99	97	99	99	N/A
K2 Wind	99	98	100	98	98	99	100	99
Kingsbridge 1	99	98	98	98	98	98	95	98
Port Dover and Nanticoke	98	94	99	100	96	93	100	98
Quality Wind	95	94	97	97	96	91	99	97
EnPower	97	100	86	97	96	95	98	N/A
	99	98	98	99	98	98	99	99
U.S. contracted facilities								
Roxboro, North Carolina	97	100	99	88	100	99	100	93
Southport, North Carolina	83	100	95	89	99	97	86	92
Decatur Energy, Alabama	85	100	94	100	89	100	100	N/A
Arlington Valley, Arizona	94	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Beaufort Solar, North Carolina	97	100	98	93	97	97	90	97
Bloom Wind, Kansas	100	97	96	98	98	97	98	N/A
Macho Springs, New Mexico	99	97	98	97	98	98	96	98
New Frontier, North Dakota	98	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	89	99	95	98	92	99	96	94

Financial results

(unaudited, $ millions)	Three months ended							
	Dec 31 2018	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**
Revenues and other income								
Alberta commercial facilities, and portfolio optimization	150	148	116	173	190	160	153	154
Alberta contracted facilities	71	70	66	61	64	61	55	61
Ontario and British Columbia contracted facilities	47	31	35	44	48	31	32	35
U.S. contracted facilities	63	74	102	65	58	77	37	29
Corporate [1]	13	15	15	15	19	14	16	14
Unrealized changes in fair value of commodity derivatives and emission credits	(9)	51	29	(51)	(118)	3	(92)	45
	335	**389**	**363**	**307**	**261**	**346**	**201**	**338**
Adjusted EBITDA								
Alberta commercial facilities, and portfolio optimization	62	60	51	55	60	55	55	58
Alberta contracted facilities	53	54	51	45	47	41	37	45
Ontario and British Columbia contracted facilities [2]	47	31	39	53	54	31	40	40
U.S. contracted facilities	25	44	72	35	30	46	10	6
Corporate	(21)	(16)	(12)	(15)	(19)	(12)	(17)	(15)
Unrealized changes in fair value of commodity derivatives and emission credits	(53)	(35)	22	(1)	(18)	(3)	(29)	9
	113	**138**	**223**	**172**	**154**	**158**	**96**	**143**

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 K2 Wind and York Energy joint ventures. Capital Power's share of K2 Wind was disposed of effective December 31, 2018 (see Significant Events).

Quarterly revenues, net income 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, and planned and unplanned facility outages and items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's power, natural gas and foreign exchange derivative contracts.

Financial highlights

(unaudited, $ millions except per share amounts)	Three months ended							
	Dec 31 2018	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**
Revenues and other income	335	389	363	307	261	346	201	338
Adjusted EBITDA [1,2]	113	138	223	172	154	158	96	143
Net income (loss)	139	19	68	41	(13)	(7)	107	47
Net income (loss) attributable to shareholders of the Company	141	20	70	43	(10)	(5)	109	50
Basic earnings (loss) per share ($)	1.27	0.10	0.57	0.32	(0.20)	(0.13)	1.03	0.44
Normalized earnings per share ($) [1]	0.33	0.35	0.22	0.30	0.24	0.28	0.27	0.34
Net cash flows from operating activities	133	65	109	143	75	120	78	99
Adjusted funds from operations [1,3]	80	156	76	85	94	135	44	88
Adjusted funds from operations per share ($) [1]	0.78	1.52	0.74	0.82	0.90	1.30	0.45	0.91
Purchase of property, plant and equipment and other assets	114	135	66	40	42	28	63	85

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 K2 Wind and York Energy joint ventures.

3 Commencing with the Company's March 31, 2018 quarter-end, the reported adjusted funds from operations measure was refined to better reflect the purpose of the measure (see Non-GAAP Financial Measures). The applicable comparable periods have been adjusted to conform to the current period's presentation.

	Three months ended							
Spot price averages	**Dec 31 2018**	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**
Alberta power ($ per MWh)	56	55	56	35	22	25	19	22
Alberta natural gas (AECO) ($ per Gj)	1.59	1.15	1.10	1.99	1.73	1.34	2.62	2.56
Capital Power's Alberta portfolio average realized power price ($ per MWh)	52	54	51	47	46	49	52	55

Factors impacting results for the fourth quarter of 2018

For the quarter ended December 31, 2018, the Company recorded net income attributable to shareholders of $141 million compared to net loss attributable to shareholders $10 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 $27 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 lower adjusted EBITDA in the fourth quarter of 2018 compared to the fourth quarter of 2017 primarily due to higher unrealized losses on commodity derivatives and emission credits in 2018 which were higher by $35 million.

Factors impacting results for the previous quarters

For the quarter ended September 30, 2018, the Company recorded net income attributable to shareholders of $20 million compared to net loss attributable to shareholders of $5 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 $8 million in the third quarter of 2018 compared to income tax recovery of $8 million in the third quarter of 2017. Adjusted EBITDA was also lower in the third quarter of 2018 compared to the third quarter of 2017 primarily due higher energy purchases and fuel resulting from higher dispatch and lower other income due to lower Modified Accelerated Costs Recovery (MACRS) at Bloom Wind resulting from U.S. tax reforms which reduced the rate to 25% in 2018 compared to 35% in 2017. These adjusted EBITDA variances were partially offset by the impact of higher Alberta power prices in 2018 compared with 2017 on the Alberta contracted assets, and higher revenue at Decatur Energy due to higher generation.

For the quarter ended June 30, 2018, the Company recorded net income attributable to shareholders of $70 million compared to $109 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 $43 million compared to $50 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.

For the quarter ended December 31, 2017, the Company recorded net loss attributable to shareholders of $10 million compared to net income attributable to shareholders of $28 million for the quarter ended December 31, 2016. The decrease compared to the prior quarter mainly resulted from lower average realized prices on the Alberta portfolio and unrealized losses on the Alberta power portfolio that were primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the period. Adjusted EBITDA was higher quarter over quarter mostly due to the impact of the acquired thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. During the fourth quarter of 2017, the U.S. federal income tax rate decreased as part of the U.S. tax reform and the Company's U.S. deferred tax assets and liabilities were re-measured. As a result of the re-measurement, the Company recognized $31 million in deferred income tax expense. In the fourth quarter of 2017, the Company also recorded a current provision of $9 million related to the LLR proceeding based on current Module C conclusions.

Financial results for the third quarter of 2017 reflected the impact of low Alberta power pricing averaging $25 per MWh. Revenues were lower compared with the corresponding period in 2016 mainly due to lower average realized prices on the Alberta portfolio and unrealized losses on the Alberta power portfolio that were primarily due to the reversal of prior period unrealized net gains on forward sales contracts that settled during the period. Adjusted EBITDA increased quarter over quarter mostly attributable to the acquisition of the thermal facilities and Decatur Energy in the second quarter of 2017 and other income related to coal compensation from the Province of Alberta. The Company recognized 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 results for the second quarter of 2017 reflected low Alberta power pricing and realized power prices. The Company completed the acquisitions of the thermal power business of Veresen Inc. and Decatur Energy. The Company also reversed 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. Despite these acquisitions, adjusted EBITDA was lower in the second quarter of 2017 compared to the second quarter of 2016 primarily due to lower realized power prices in 2017 compared with 2016 and unrealized losses on net forward natural gas purchase contracts valued against decreasing forward natural gas prices in 2017 compared with net forward natural gas purchase contracts valued against increasing forward natural gas prices in 2016.

Financial results for the first quarter of 2017 and 2016 reflected low Alberta power pricing and realized power prices. Adjusted EBITDA increased quarter over quarter mainly due to unrealized gains on net forward power sales contracts valued against decreasing prices and other income related to coal compensation from the Province of Alberta. The Company’s normalized earnings per share of $0.34 in the first quarter of 2017 was consistent with the normalized earnings per share of $0.33 in the first quarter of 2016 after adjustment for the $46 million post-tax loss as a result of the de-recognition of the Sundance PPA intangible asset in the first quarter of 2016.

SHARE AND PARTNERSHIP UNIT INFORMATION

Quarterly common share trading information

The Company’s common shares are listed on the TSX under the symbol CPX and began trading on June 26, 2009.

	Three months ended							
	Dec 31 2018	**Sep 30 2018**	**Jun 30 2018**	**Mar 31 2018**	**Dec 31 2017**	**Sep 30 2017**	**Jun 30 2017**	**Mar 31 2017**
Share price ($/common share)								
High	29.79	29.45	26.00	25.14	25.59	26.51	26.14	26.43
Low	25.33	25.12	23.42	22.15	23.26	23.81	24.05	23.15
Close	26.59	28.51	25.23	24.24	24.49	24.67	24.32	26.06
Volume of shares traded (millions)	25.5	14.8	11.1	14.0	16.9	14.1	14.8	17.0

Outstanding share and partnership unit data

As at February 12, 2019, the Company had 101.748 million common shares, 5 million Cumulative Rate Reset Preference Shares (Series 1), 6 million Cumulative Rate Reset Preference Shares (Series 3), 8 million Cumulative Rate Reset Preference Shares (Series 5), 8 million Cumulative Minimum Rate Reset Preference Shares (Series 7), 6 million Cumulative Minimum Rate Reset Preference Shares (Series 9) 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 12, 2019 were 105.066 million. The outstanding special limited voting share is held by EPCOR.

As at February 12, 2019, 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, 2018 and 2017

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 15, 2019. Financial information presented elsewhere in the Company's 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 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 15, 2019

CAPITAL POWER CORPORATION

Consolidated Financial Statements

Years ended December 31, 2018 and 2017

KPMG LLP
2200, 10175 – 101 Street
Edmonton, AB T5J 0H3
Telephone (780) 429-7300
Fax (780) 429-7379
www.kpmg.ca

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, 2018 and December 31, 2017
- the consolidated statements of income and 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, 2018 and December 31, 2017, 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 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.

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 "2018 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 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.

The information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2018 Annual Report" is expected to be made available to us after the date of this auditors' report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

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.

KPMG LLP

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

Chartered Professional Accountants

Edmonton, Canada

February 15, 2019

CAPITAL POWER CORPORATION

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

Years ended December 31

	2018	2017
Revenues	$ 1,249	$ 1,046
Other income (note 5)	145	100
Energy purchases and fuel (note 6)	(434)	(318)
Gross margin	960	828
Other raw materials and operating charges	(124)	(114)
Staff costs and employee benefits expense (note 6)	(145)	(129)
Depreciation and amortization (note 6)	(300)	(271)
Other administrative expense (note 6)	(96)	(89)
Foreign exchange gain	10	28
Impairments (note 11)	-	(83)
Operating income	305	170
Gain on disposal of joint venture (note 7)	159	-
Net finance expense (note 8)	(123)	(108)
Income from joint ventures (note 36)	19	31
Income before tax	360	93
Income tax (expense) recovery (note 9)	(93)	41
Net income	$ 267	$ 134
Attributable to:		
Non-controlling interests (note 35)	$ (7)	$ (10)
Shareholders of the Company	$ 274	$ 144

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

	2018	2017
Basic (note 10)	$ 2.25	$ 1.07
Diluted (note 10)	$ 2.25	$ 1.07

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

	2018	2017
Net income	$ 267	$ 134
Other comprehensive income (loss):		
Items that will not be reclassified subsequently to net income:		
Defined benefit plans:		
Actuarial gains (losses) [1]	2	(1)
Items that are or may be reclassified subsequently to net income:		
Cash flow hedges:		
Unrealized gains (losses) on derivative instruments [2]	15	(4)
Unrealized gains on derivative instruments – joint ventures (note 36) [3]	3	3
Reclassification of losses (gains) on derivative instruments to income for the year [4]	14	(63)
Reclassification of losses on derivative instruments to income for the year – joint ventures (note 36) [5]	2	3
Net investment in foreign subsidiaries:		
Unrealized gains (losses) [6]	50	(53)
Losses realized in net income on disposal of joint venture (note 7)[7]	12	-
Total items that are or may be reclassified subsequently to net income, net of tax	96	(114)
Total other comprehensive income (loss), net of tax	98	(115)
Total comprehensive income	$ 365	$ 19
Attributable to:		
Non-controlling interests (note 35)	$ (7)	$ (10)
Shareholders of the Company	$ 372	$ 29

[1] For the year ended December 31, 2018, net of income tax expense of $1. For the year ended December 31, 2017, net of income tax of nil.

[2] For the year ended December 31, 2018, net of income tax expense of $6. For the year ended December 31, 2017, net of income tax recovery of $4.

[3] For the years ended December 31, 2018 and December 31, 2017 net of income tax expense of $1.

[4] For the year ended December 31, 2018, net of reclassification of income tax recovery of $5. For the year ended December 31, 2017, net of reclassification of income tax expense of $23.

[5] For the years ended December 31, 2018 and December 31, 2017 net of reclassification of income tax recovery of $1.

[6] For the years ended December 31, 2018 and December 31, 2017, net of income tax of nil.

[7] For the year ended December 31, 2018, net 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

	2018	2017
Assets		
Current assets:		
Cash and cash equivalents (note 12)	$ 182	$ 52
Trade and other receivables (note 13)	462	278
Inventories (note 14)	200	120
Derivative financial instruments assets (note 15)	77	92
	921	542
Non-current assets:		
Other assets	66	68
Derivative financial instruments assets (note 15)	82	79
Finance lease receivables (note 16)	620	644
Government grant receivable (note 17)	459	493
Deferred tax assets (note 18)	59	74
Equity-accounted investments in joint ventures (note 36)	142	184
Intangible assets (note 19)	473	401
Property, plant and equipment (note 20)	4,803	4,378
Goodwill (note 21)	35	35
Total assets	$ 7,660	$ 6,898

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

	2018	2017
Liabilities and equity		
Current liabilities:		
Trade and other payables (note 22)	$ 245	$ 216
Derivative financial instruments liabilities (note 15)	90	86
Loans and borrowings (note 23)	456	239
Deferred revenue and other liabilities (note 25)	61	58
Provisions (note 26)	54	37
	906	636
Non-current liabilities:		
Derivative financial instruments liabilities (note 15)	114	56
Loans and borrowings (note 23)	2,191	1,907
Finance lease obligation (note 16)	17	17
Deferred revenue and other liabilities (note 25)	587	581
Deferred tax liabilities (note 18)	435	374
Provisions (note 26)	291	265
	3,635	3,200
Equity:		
Equity attributable to shareholders of the Company		
Share capital (note 27)	3,200	3,262
Deficit	(156)	(181)
Other reserves (note 28)	32	(67)
Deficit and other reserves	(124)	(248)
	3,076	3,014
Non-controlling interests (note 35)	43	48
Total equity	3,119	3,062
Total liabilities and equity	$ 7,660	$ 6,898

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board:

Donald Lowry
Director and Chair of the Board

Philip Lachambre
Director and Chair of the Audit Committee

CAPITAL POWER CORPORATION

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

	Share Capital (note 27)	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 35)	Total
Equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (181)	$ 3,014	$ 48	$ 3,062
Impact of accounting policy change (note 2(c))	-	-	-	-	-	(44)	(44)	-	(44)
Tax impact of accounting policy change (note 2(c))	-	-	-	-	-	11	11	-	11
Adjusted equity as at January 1, 2018	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (214)	$ 2,981	$ 48	$ 3,029
Net income	-	-	-	-	-	274	274	(7)	267
Other comprehensive income:									
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 7)	-	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	-	274	372	(7)	365
Investment in non-controlling interests (note 35)	-	-	-	-	-	-	-	2	2
Tax on change in non-controlling interests ownership	-	-	-	-	-	4	4	-	4
Common share dividends (note 27)	-	-	-	-	-	(178)	(178)	-	(178)
Preferred share dividends (note 27)	-	-	-	-	-	(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	$ (156)	$ 3,076	$ 43	$ 3,119

[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 Changes in Equity
(In millions of Canadian dollars)

	Share capital (note 27)	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 35)	Total
Equity as at January 1, 2017	$ 2,918	$ 22	$ 26	$ (10)	$ 11	$ (124)	$ 2,843	$ 58	$ 2,901
Net income	-	-	-	-	-	144	144	(10)	134
Other comprehensive loss:									
Defined benefit plan actuarial loss	-	-	-	(1)	-	-	(1)	-	(1)
Cash flow derivative hedge losses	-	(8)	-	-	-	-	(8)	-	(8)
Cash flow derivative hedge gains – joint ventures	-	4	-	-	-	-	4	-	4
Reclassification of gains to net income	-	(86)	-	-	-	-	(86)	-	(86)
Reclassification of losses to net income – joint ventures	-	4	-	-	-	-	4	-	4
Unrealized loss on foreign currency translation	-	-	(53)	-	-	-	(53)	-	(53)
Tax on items recognized directly in equity	-	25	-	-	-	-	25	-	25
Other comprehensive loss	$ -	$ (61)	$ (53)	$ (1)	$ -	$ -	$ (115)	**$ -**	$ (115)
Total comprehensive (loss) income	-	(61)	(53)	(1)	-	144	29	(10)	19
Common share dividends (note 27)	-	-	-	-	-	(165)	(165)	-	(165)
Preferred share dividends (note 27)	-	-	-	-	-	(35)	(35)	-	(35)
Tax on preferred share dividends	-	-	-	-	-	(1)	(1)	-	(1)
Issue of common share capital	183	-	-	-	-	-	183	-	183
Issue of preferred share capital	150	-	-	-	-	-	150	-	150
Share issue costs	(11)	-	-	-	-	-	(11)	-	(11)
Deferred taxes on share issue costs	3	-	-	-	-	-	3	-	3
Share-based payments	-	-	-	-	1	-	1	-	1
Share options exercised	19	-	-	-	(2)	-	17	-	17
Equity as at December 31, 2017	$ 3,262	$ (39)	$ (27)	$ (11)	$ 10	$ (181)	$ 3,014	$ 48	$ 3,062

[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 Cash Flows
(In millions of Canadian dollars)

Years ended December 31

	2018	2017
Cash flows from operating activities:		
Net income	$ 267	$ 134
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Gain on disposal of joint venture (note 7)	(159)	-
Impairments (note 11)	-	83
Depreciation and amortization (note 6)	300	271
Net finance expense (note 8)	123	108
Fair value changes on commodity derivative instruments and emission credits held for trading	67	41
Foreign exchange gains	(10)	(28)
Income tax expense (recovery) (note 9)	93	(41)
Income from joint ventures (note 36)	(19)	(31)
Reduction in finance lease receivables	23	22
Recognition of government grant deferred revenue	(51)	(51)
Tax equity attributes (note 5)	(80)	(32)
Other items	6	11
Change in fair value of derivative instruments reflected as cash settlement	21	(5)
Distributions received from joint ventures (note 36)	30	27
Interest paid [1]	(96)	(81)
Other cash items (note 29)	(22)	(16)
Change in non-cash operating working capital (note 29)	(43)	(40)
Net cash flows from operating activities	450	372
Cash flows used in investing activities:		
Purchase of property, plant and equipment and other assets	(355)	(218)
Business acquisitions, net of acquired cash (note 4)	(399)	(839)
Proceeds on disposal of joint venture (note 7)	126	-
Government grant received	50	50
Genesee Coal Mine prepayment	-	(70)
Other cash flows from investing activities	-	17
Change in non-cash investing working capital	24	(54)
Net cash flows used in investing activities	(554)	(1,114)
Cash flows from financing activities:		
Proceeds from issue of loans and borrowings	705	1,098
Repayment of loans and borrowings	(195)	(507)
Issue costs on loans and borrowings	(6)	(10)
Issue of shares (note 27)	-	333
Share issue costs (note 27)	-	(11)
Proceeds from exercise of share options	14	17
Common shares purchased (note 27)	(76)	-
Dividends paid (note 27)	(217)	(194)
Realized gains (losses) on settlement of foreign exchange derivatives	33	(12)
Capitalized interest paid [1]	(5)	(6)
Income taxes paid on preferred share dividends	(19)	(10)
Other cash flows used in financing activities	(1)	(1)
Net cash flows from financing activities	233	697
Foreign exchange gain (loss) on cash held in a foreign currency	1	(1)
Net increase (decrease) in cash and cash equivalents	130	(46)
Cash and cash equivalents, beginning of year	52	98
Cash and cash equivalents, end of year	$ 182	$ 52

[1] Total interest paid.

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 15, 2019.

(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 Capital Power L.P. (CPLP) (2017 – 100%). Capital Power controls CPLP and therefore CPLP is treated as a subsidiary of Capital Power.

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, 2018, the Company adopted the following new accounting standards:

IFRS 15 – Revenue from Contracts with Customers

The objective of this standard is to provide a single and comprehensive framework for revenue recognition that replaces previous revenue standards. The objective of the disclosure requirements is to enable users of the financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

The Company’s revenues from contracts with customers within the scope of IFRS 15 consist mainly of the sale of electricity and natural gas based on energy sales agreements, capacity agreements and emission credit sales. Energy revenues are billed to the customer based on the market price at the time of performance or observable contract prices depending on the terms of the agreement.

The Company has applied IFRS 15 using the cumulative effect method, recognizing the cumulative effect of initially applying IFRS 15 as an adjustment to the opening deficit balance as at January 1, 2018. Therefore, the comparative information has not been restated and continues to be reported under IAS 18 – Revenue. The adoption of this standard has resulted in the opening deficit adjustments described below as well as additional disclosures regarding revenues as summarized in note 2(h).

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

IFRS 15 – Revenue from Contracts with Customers, continued

The timing of revenue recognition, billing and cash collection does not differ from the Company's previous accounting policies under IAS 18 other than as described below. As such, the adoption of this standard resulted in a pre-tax increase to the opening deficit at January 1, 2018 of $44 million ($33 million post tax).

- The Joffre Cogeneration Project (Joffre), a joint operation of the Company accounted for under IFRS 11 – Joint Arrangements, sells power generation capacity under an energy supply agreement. The performance obligation to provide availability of the contracted power generation over the contract term is satisfied over the contract term. The capacity payments are based on a declining rate base capacity payment schedule and were previously recognized under IAS 18 as revenues when the Company had the right to bill. Upon the adoption of IFRS 15, revenues are recognized as the performance obligation is satisfied. The Company recorded a pre-tax increase to the opening deficit at January 1, 2018 of $41 million ($31 million post tax) and increased deferred revenue and other liabilities for a contract liability due to the change in the timing of capacity payment revenue recognition for the cumulative effect of initially applying IFRS 15. The contract liability will be recognized as revenue over the term of the Energy Supply Agreement which continues until the plant is decommissioned at the end of its useful life (2041) or until the agreement is terminated. For the year ended December 31, 2018, no revenue has been recognized related to the contract liability balance and no conditional unbilled receivables (contract assets) have been recorded.
- Prior to the adoption of IFRS 15, the Company recognized revenue on the sale of certain Renewable Energy Credits (RECs) at the time of generation. Under IFRS 15, the Company satisfies its performance obligation when RECs are delivered to the customer which occurs subsequent to the period of REC generation. As such, the Company recorded an adjustment for the change in timing of REC revenue recognition for the cumulative effect of initially applying IFRS 15 resulting in a pre-tax increase to the opening deficit at January 1, 2018 of $3 million ($2 million post tax).

IFRS 9 – Financial Instruments

The objective of this standard is to set out requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items, improve transparency in the disclosure of expected credit losses and to improve the overall usefulness of financial statements for users by revising the current hedge accounting requirements.

As a result of the adoption of IFRS 9 as at January 1, 2018, the Company's accounting policy for financial instruments has been modified with the nature and effects of key changes summarized in the following notes:

- Classification and Measurement of non-derivative financial assets and liabilities – note 2(j)
- Derivative instruments and hedging activities – note 2(k)
- Impairment of financial assets – note 2(p)

The change in accounting policy has been applied retrospectively and did not result in a change in the carrying amount of any financial instruments at the transition date. Additionally, the Company adopted consequential amendments to IFRS 7: Financial Instruments: Disclosures that have been applied commencing January 1, 2018. The Company has elected not to restate comparative information, and as a result, the prior year continues to be accounted for in accordance with its previous accounting policy.

The Company completed an assessment of its classification of financial assets and liabilities as at January 1, 2018 under IFRS 9. The standard required classification of financial instruments in the following categories: fair value through income or loss (FVTIL), fair value through other comprehensive income (FVTOCI) or amortized cost. The following table shows the original classification under IAS 39 and the new classification under IFRS 9:

2. Significant accounting policies, continued:

(c) Current accounting changes, continued:

IFRS 9 – Financial Instruments, continued

Financial assets and liabilities	Original (IAS 39)	New (IFRS 9)
Financial assets		
Cash and cash equivalents	Loans and receivables[1]	Amortized cost
Trade and other receivables	Loans and receivables[1]	Amortized cost
Finance lease receivables	Loans and receivables[1]	Amortized cost
Government grant receivable	Loans and receivables[1]	Amortized cost
Derivative financial instruments assets		
Non-hedges	FVTIL	FVTIL
Cash flow hedges	FVTOCI	FVTOCI
Financial liabilities		
Trade and other payables	Other financial liabilities[1]	Amortized cost
Derivative financial instruments liabilities		
Non-hedges	FVTIL	FVTIL
Cash flow hedges	FVTOCI	FVTOCI
Loans and borrowings	Other financial liabilities[1]	Amortized cost
Finance lease obligations	Other financial liabilities[1]	Amortized cost

[1] Measured at amortized cost.

(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.

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

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.

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 ventures

The Company, has equal interests in partnerships with other external parties where, by contractual agreement, each of the Partners effectively has rights to the net assets of the arrangements and as a result the arrangements are considered to be joint ventures.

The Company's investments in these joint ventures are accounted for under the equity method, and were recognized initially at cost and the carrying amount is increased or decreased to recognize the Company's share of the joint ventures' total comprehensive income or loss after the date of acquisition. Distributions received from the joint ventures reduce the carrying amount of these investments. The accounting policies of the joint ventures are aligned with the accounting policies of the Company except, in one instance, the Company considers that the power purchase agreement associated with the wind power project contains a lease, whereas the joint venture does not. The Company applies lease accounting principles in the calculation of the Company's share of this joint venture's total comprehensive income or loss.

(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) related to the phase-out of coal-fired generation by the end of 2030 (see note 17). 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 and the associated deferred revenue is accreted until settlement in 2030. The deferred revenue associated with the grant will be recognized in net income as other income on a straight-line basis through 2030 as this is the period over which costs will be incurred as a result of the 2030 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 IAS 17 – Leases (note 2(i)) and IFRS 9 – Financial Instruments as described in the following table. Disaggregated revenues are disclosed in note 39.

Contracts with customers by operational groupings are as follows:

Operational grouping	Description
Alberta Commercial	The majority of the power generated by the Company's interests in Alberta Commercial facilities is sold into energy markets on a merchant or non-contracted basis. The Company's interests in the majority of these facilities are under contractual arrangements that are considered to be joint operations. The accounting policies of these joint operations are aligned with the accounting policies of the Company and are included within the scope of IFRS 15. 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 power purchase arrangements (PPAs) determined to be leases, which are accounted for under IAS 17 – Leases and are therefore 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 also 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 contracts that are accounted for under IAS 17 – Leases and is therefore excluded from the scope of IFRS 15. The Company's joint venture interests in K2 Wind and York Energy are accounted for under IFRS 11 – Joint Arrangements under the equity method. The accounting policies of York Energy and K2 Wind are aligned with the accounting policies of the Company. The Company's share of the joint venture facilities' net income is included in income from joint ventures on the condensed interim consolidated statements of income and as a result, these facilities are not subject to the disclosure requirements of IFRS 15. Steam production sales are 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 determined to be leases, is accounted for under IAS 17 – Leases and therefore is 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. Power generation revenues from facilities with long-term sales arrangements that are determined not to contain a lease are included in energy revenues within 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, 2018, the Company has not recorded any conditional unbilled receivables (contract assets) or customer advances and deposits (contract liabilities) other than as described in note 2 (c).

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 recorded as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenues

Payments received on one of the Company's operating leases may be in excess of accounting lease revenues. In such cases, the Company records deferred revenue on its consolidated statement of financial position.

The Company records any gains resulting from sale and leaseback transactions as deferred revenue on its consolidated statement 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:

The Company has entered into PPAs to sell power at predetermined prices. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment. If the PPAs are determined to contain a lease, the arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer substantially all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

For those PPAs determined to be finance leases with the Company as the lessor, finance income is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized into net income over the lease term.

Payments received under PPAs classified as finance leases are segmented into those for the lease and those for other elements of the PPA on the basis of their relative fair values.

For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight-line basis unless another method better represents the earnings process.

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.

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, finance lease receivables and the government grant receivable.

2. Significant accounting policies, continued:

(j) Non-derivative financial instruments, continued:

Measurement, continued

Financial assets and liabilities at amortized cost, continued

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 loans and borrowings, finance lease obligation and trade and other payables 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 enable access to U.S. income tax benefits such as investment tax credits (ITCs), cash grants, production tax credits (PTCs) 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.

Classification and measurement

Financial assets and liabilities at fair value through other comprehensive income

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 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.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Classification and measurement, continued

Financial assets and liabilities at fair value through other comprehensive income, continued

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. This accounting policy remains unchanged from IAS 39 and derivative instruments continue to be 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.

Commodity derivative instruments

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

The Company uses non-financial forward delivery derivatives to manage the Company's exposure to fluctuations in natural gas prices related to its natural gas customer contracts and obligations arising from its natural gas-fired generation facilities. Under these instruments, the Company agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity for a specified timeframe.

The Company may use non-financial or financial commodity derivative instruments with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities. Such transactions are recognized on a net basis in the Company's revenues.

Interest rate derivative instruments

The Company may use cross-currency interest rate swaps to manage the foreign currency exchange risk on U.S. dollar denominated loans and borrowings. Under these instruments, the Company and the counterparties exchange principal amounts at initiation of the transaction, whereby the Company pays the counterparties U.S. dollar principal amounts and the counterparties pay the Company Canadian dollar principal amounts. Over the terms of these instruments, the Company makes fixed rate interest payments in Canadian dollars on the initial principal to the counterparties while the counterparties make fixed rate interest payments in U.S. dollars to the Company.

The Company may use Bond Locks and Forward Starting Swaps to manage interest rate exposure by fixing the Company's interest rate risk associated with movements in Government of Canada (GoC) bonds. A Bond Lock is typically used for terms of less than 12 months where a specific underlying GoC bond can be identified. For hedge terms around 12 months or longer credit swaps allow a lock in of both the 'on the run' treasury rates as a benchmark as well as the current market credit spreads. The Company may use fixed for floating interest rate swaps to optimize its mix of loans and borrowings at fixed interest rates and those at floating interest

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Interest rate derivative instruments, continued

rates. Under these instruments, the Company agrees to pay the counterparties floating rate interest payments in exchange for the counterparties paying the Company fixed rate interest payments on the notional amount of loans and borrowings.

Foreign exchange derivative instruments

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of net assets, when the real or anticipated transaction subsequently results in the recognition of an asset or business, the associated gains or losses on derivative instruments are included in the initial carrying amount of the asset or business acquired in the same period or periods in which the asset or business is acquired or constructed.

Hedge accounting

IFRS 9 introduces a new hedge accounting model that aligns hedge accounting more closely with risk management by expanding the scope of hedged items and risks eligible for hedge accounting. As part of the new model, effectiveness testing no longer specifies quantitative measures and does not permit voluntary hedge de-designation.

The Company has applied the new general hedge accounting model prospectively and determined no changes to its hedging relationships previously designated under IAS 39.

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.

The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices and to reduce exposure to currency risk and interest rate risk pertaining to the variability of cash flows on U.S. dollar loans and borrowings and on interest rates on financing, respectively. 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.

2. Significant accounting policies, continued:

(k) Derivative instruments and hedging activities, continued:

Hedge accounting, continued

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.

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 19 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. Coal supply access rights are amortized over the remaining life of the Keephills 3 facility. 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 to 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 (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.

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

IFRS 9 introduces a forward-looking 'expected credit loss' (ECL) impairment model which applies to all financial assets measured at amortized cost or FVTOCI. 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.

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, including finance lease receivables. No impairment provision has been recorded by the Company as at December 31, 2018 related to trade and other receivables and finance lease receivables and the Company considers these financial assets to be low risk.

2. Significant accounting policies, continued:

(p) Impairment of assets, continued:

Financial assets, continued

For financial assets measured at FVTOCI, expected allowances are recognized as 12-month expected credit losses (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, 2018. Credit risk management procedures, including risk mitigation practices, are as described in the risk management note 33.

(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 the employee services received in exchange for the grant of the options is recognized 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).

2. Significant accounting policies, continued:

(u) Share-based payments, continued:

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.

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 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 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.

(w) Future accounting changes:

IFRS 16 – Leases – The new standard which replaces 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. IFRS 16 is effective for annual periods beginning on or after January 1, 2019.

The Company has 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 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. The Company will recognize a right-of-use asset for the underlying asset and a lease liability for future lease payments.

Management has determined that certain PPAs and energy supply contracts that are currently considered to be finance leases with the Company as the lessor will no longer be considered leases upon adoption of this new 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 accounted for retrospectively in accordance with IAS 8 - Accounting Policies, Changes in Accounting Estimates and Errors and treated as a change in accounting policy.

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

2. Significant accounting policies, continued:

(w) Future accounting changes, continued:

The Company is in the process of finalizing its transition to IFRS 16 and the expected adjustments to the consolidated statements of financial position as a result of the changes described above are as follows:

	Leases as the lessee			Leases as the lessor			
	IAS 17 (Old)	IFRS 16 (New)	Impact	IAS 17 (Old)	IFRS 16 (New)	Impact	Overall Impact
As at January 1, 2019							
Assets [1]	2	86	84	644	553	(91)	(7)
Liabilities [2]	4	94	90	-	(25)	(25)	65
Opening deficit adjustment [2]	-	(6)	(6)	-	(66)	(66)	(72)
As at January 1, 2018							
Assets [1]				667	588	(79)	(79)
Liabilities [2]				-	(22)	(22)	(22)
Opening deficit adjustment [2]				-	(57)	(57)	(57)

[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 increases to the opening deficit balances, net of estimated deferred tax impacts at a rate of 27%, which also impact the liabilities amounts as reductions to deferred tax liabilities.

The expected retrospective adjustments to the consolidated statement of income for the year ended December 31, 2018 pertaining to the leases where Capital Power is the lessor are:

	IAS 17 (Old)	IFRS 16 (New)	Impact
Revenues	(23)	-	23
Depreciation and amortization	-	(35)	(35)
Income tax (expense) recovery	6	9	3
Net income (loss)	(17)	(26)	(9)

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.

3. Use of judgments and estimates, continued:

Critical judgments in applying accounting policies, continued

Classification of arrangements which contain a lease

As noted in note 2(i), the Company has exercised judgment in determining whether the risks and rewards 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 and if so, whether the lease should be treated as a finance or operating lease. Details of those PPAs which contain either finance or operating leases are provided in note 16.

The Company has exercised judgment in determining the classification of lease arrangements under the new leasing standard, as described in note 2(w), which includes assessing the right to direct the use of the assets associated with each agreement that was evaluated.

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 35.

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 36.

Operating segments

As noted in note 39, 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 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.

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

Measurement of fair values, continued

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 (NYMEX) whereby the Company can obtain quoted prices for identically traded commodities.
- Level 2: Fair value is based on other than unadjusted 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.
- 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. As at December 31, 2018, the Company classified $16 million of derivative financial instruments assets (2017 – $32 million) and $44 million of derivative financial instruments liabilities (2017 – $2 million) in Level 3 of the hierarchy.

The Company's policy is to recognize transfers between levels as of the date of the event of change in circumstances that caused the transfer. As at December 31, 2018, the Company recognized a fair value transfer from Level 3 to Level 2 of $5 million (2017 - $2 million) as pricing inputs of derivative type instruments became available.

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

- Note 4 – Business acquisitions;
- Note 11 – Impairment testing;
- Note 14 – Inventories - emissions credits;
- Notes 15 and 32 – Financial instruments;
- Note 26 – Provisions; and
- Note 31 – 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 2017 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.

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

3. Use of judgments and estimates, continued:

Key sources of estimation uncertainty, continued

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 18.

Revenue recognition

As noted in note 2(h), estimates of the value of electricity and natural gas consumed by customers but not billed until after the reporting period-end are based on contracted prices and volume data provided by the parties responsible for delivering the commodity.

Actual results may differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

4. Business acquisitions:

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 facility). The Arlington facility is a 580 Megawatt (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 preliminary working capital and other closing adjustments of $3 million (US$3 million).

The preliminary 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 – non-current		(2)
Provisions – non-current		(11)
Fair value of net assets acquired	$	399

The purchase price allocation is subject to the finalization of working capital adjustments which is expected to occur in the first half of 2019.

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 the Arlington facility 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 statement of financial position. Since the acquisition date, $6 million of revenues and $2 million net loss are 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 the Arlington facility would have had a total of $1,341 million of revenues for the year ended December 31, 2018.

In conjunction with the acquisition of the Arlington facility, for the year ended December 31, 2018, the Company incurred $2 million in acquisition costs which have been 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)

4. Business acquisitions, continued:

Acquisition of Decatur Energy

On June 13, 2017, a subsidiary of the Company acquired all of the equity interests in Decatur Power Holdings, LLC, which owns Decatur Energy Centre (Decatur Energy), from an affiliate of LS Power Equity Partners III. Decatur Energy is a 795 Megawatt (MW) natural gas-fired combined cycle power generation facility located in Alabama. The purchase price consisted of $603 million (US$448 million) in total cash consideration, including working capital and other closing adjustments of $9 million (US$7 million). The allocation of the purchase price to the assets acquired and liabilities assumed based on their estimated fair values is as described below.

Acquisition of thermal facilities

During the first quarter of 2017, the Company entered into an agreement to acquire the thermal power business of Veresen Inc. On April 13, 2017, the Company announced that it had completed the acquisition of the two natural gas-fired power facilities in Ontario consisting of the 84 MW East Windsor Cogeneration Center (East Windsor) and a 50% interest in the 400 MW York Energy Center (York Energy). The purchase price for the natural gas-fired facilities consisted of (i) $235 million in total cash consideration, including working capital and other closing adjustments of $12 million, and (ii) the assumption of $254 million of project level debt (proportionate basis at acquisition date net book value). On June 1, 2017, the Company completed the acquisition of EnPower Green Energy Generation (EnPower) consisting of 10 MW of zero-emissions waste heat generation from two facilities (5 MW each) in British Columbia. The purchase price consisted of (i) $8 million of total cash consideration, including working capital and other closing adjustments of $3 million, and (ii) the assumption of $18 million of project level debt.

Purchase price allocation information – 2017 acquisitions

The allocations of the respective purchase prices to the assets acquired and liabilities assumed based on their estimated fair values was as follows:

	Decatur Energy	East Windsor	York Energy	EnPower	Total
Cash and cash equivalents	$ 1	$ 4	$ -	$ 2	$ 7
Trade and other receivables	8	6	-	-	14
Inventories	4	2	-	-	6
Equity accounted investment in joint venture	-	-	153	-	153
Intangible assets	44	3	-	-	47
Property, plant and equipment	518	202	-	28	748
Goodwill	41	36	-	-	77
Trade and other payables	(2)	(1)	-	-	(3)
Loans and borrowings	-	(153)	-	(18)	(171)
Provisions	(11)	(1)	-	(1)	(13)
Deferred tax liabilities	-	(16)	-	(3)	(19)
Fair value of net assets acquired	$ 603	$ 82	$ 153	$ 8	$ 846

These acquisitions support the Company's growth strategy and are consistent with the Company's technology and operating focus.

The amounts allocated to trade and other receivables for the acquisitions above represent both the estimated fair value and the gross contractual amounts receivable.

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

4. Business acquisitions, continued:

Purchase price allocation information – 2017 acquisitions, continued

The goodwill recognized on the acquisition of East Windsor was primarily attributable to the potential for favourable re-contracting of the facility or favourable commercial alternatives at the end of the current long-term contract and the recognition of deferred tax liabilities associated with the acquisition. The goodwill recognized on the acquisition of Decatur Energy was primarily attributable to the ability to utilize a portion of the Company's U.S. income tax loss carryforwards. As required by the international accounting standard pertaining to income taxes, these U.S. income tax loss carryforwards were recognized as a deferred tax asset in the second quarter of 2017 (see note 9) and as a result, the goodwill associated with Decatur Energy was subsequently impaired during the Company's annual impairment testing of CGUs containing goodwill in the third quarter of 2017 (see note 11). All goodwill recorded related to the Decatur Energy acquisition was deductible for tax purposes, while the goodwill pertaining to East Windsor is not deductible for tax purposes.

The project level debt assumed related to East Windsor bears interest at a rate of 6.28%, is repayable quarterly, and matures in September 2029. The project level debt assumed related to EnPower was repaid in October 2017.

The results of operations of Decatur Energy, East Windsor, York Energy and EnPower are included in the Company's consolidated statements of income and statements of changes in equity from their respective dates of acquisition. Such results of operations and the related assets and liabilities at the statement of financial position date are included in the consolidated statement of financial position. Since each respective acquisition date, the following revenues and income were included in the consolidated statements of income for the year ended December 31, 2017, respectively:

	For the year ended December 31, 2017				
	Decatur Energy	East Windsor	York Energy	EnPower	Total
Revenues	$ 46	$ 25	$ N/A[2]	$ 2	$ 73
Net (loss) income[1]	(14)	3	4	-	(7)

[1] The net loss for Decatur Energy includes an impairment of $37 million related to that CGU (see note 11).

[2] The investment in York Energy is accounted for under the equity method and therefore revenues from this facility are not directly reflected per the above disclosure (see note 36).

Had the acquisitions occurred at January 1, 2017, the combined entity of the Company, Decatur Energy, East Windsor, York Energy and EnPower would have had a total of $1,082 million of revenues and $141 million of net income for the year ended December 31, 2017.

In conjunction with the acquisition of the thermal power business of Veresen Inc., for the year ended December 31, 2017, the Company incurred $6 million, in acquisition costs which were recorded on the Company's statement of income as other administrative expenses. In conjunction with the acquisition of Decatur Energy, for the year ended December 31, 2017, the Company incurred less than $1 million in acquisition costs.

5. Other income:

Year ended December 31	2018	2017
Contributions and grants	$ 10	$ 10
Government compensation (note 17)	51	51
Production Tax Credits (PTC)	22	12
Modified Accelerated Cost Recovery System (MACRS) depreciation	58	20
Other	4	7
Other income	$ 145	$ 100

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

6. Expenses:

Year ended December 31	2018	2017
Included in energy purchases and fuel		
Recovery of flow-through expenses related to the Genesee 1 and 2 PPA's [1]	$ (91)	$ (28)
Included in staff costs and employee benefits expense		
Share-based payments (note 31)	14	11
Post-employment defined contribution plan expense	7	7
Post-employment defined benefit plan expense	3	3
Recovery of flow-through expenses related to the Genesee 1 and 2 PPAs [1]	(1)	(1)
	23	20
Included in depreciation and amortization		
Depreciation of property, plant and equipment (note 20)	274	249
Amortization of intangible assets (note 19)	24	21
Other	2	1
	$ 300	$ 271
Included in other administrative expenses		
Operating lease payments	8	8

[1] These recoveries are based on $92 million of expenses (2017 – $29 million) included in energy purchases and fuel and staff costs and employee benefits expense.

7. Disposal of interest in joint venture:

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.

8. Net finance expense:

Year ended December 31	2018	2017
Interest expense		
Interest on loans and borrowings	$ 115	$ 105
Capitalized interest	(5)	(6)
Total interest expense	110	99
Other finance expense		
Unwinding of discount on decommissioning provisions (note 26)	5	4
Accretion on deferred government grant revenue	16	17
Interest on long-term government grant receivable	(16)	(17)
Other	8	5
Net finance expense	$ 123	$ 108

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

9. Income tax expense (recovery):

Year ended December 31	2018	2017
Current income tax		
Current income tax expense	$ 22	$ 16
Recognition of previously unrecognized tax benefits	(3)	-
Adjustments for prior periods	(1)	-
Total current income tax expense	18	16
Deferred income tax		
Origination and reversal of temporary differences	80	4
Change in U.S. tax rate [1]	-	31
Recognition of previously unrecognized tax benefits	(9)	(89)
Change in write-downs of deferred tax assets	4	(3)
Total deferred income tax expense (recovery)	75	(57)
Income tax expense (recovery)	$ 93	$ (41)

Reconciliation of effective income tax rate

Year ended December 31	2018	2017
Income before tax	$ 360	$ 93
Income tax at the statutory rate of 27.0% (2017 - 27.0%)	97	25
Increase (decrease) resulting from:		
Amounts attributable to non-controlling interests and tax equity interests [2]	29	8
Change in unrecognized tax benefits [3]	(8)	(92)
Non-taxable amounts	(29)	(17)
Adjustments for prior periods	(2)	(1)
Statutory and other rate differences	3	33
Other	3	3
Income tax expense (recovery)	$ 93	$ (41)

[1] During the fourth quarter of 2017, the U.S. Tax Cuts and Jobs Act of 2017 reduced the U.S. federal corporate tax rate. As a result, the U.S. deferred tax assets and liabilities were re-measured resulting in the recognition of deferred income tax expense of $31 million.

[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).

[3] During 2017, the Company reversed a previous write-down of deferred tax assets of $86 million 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 (both during the second quarter of 2017), it became probable that sufficient future taxable income would be available from U.S. operations to utilize the underlying losses.

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

10. Earnings per share:

Basic earnings per share

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

Year ended December 31	2018	2017
Income for the period attributable to shareholders of the Company	$ 274	$ 144
Preferred share dividends of the Company [1]	(42)	(36)
Earnings used in the calculation of basic earnings per share	$ 232	$ 108

[1] Includes preferred share dividends declared for the years ended December 31, 2018 and 2017 respectively and related taxes.

Year ended December 31	2018	2017
Weighted average number of common shares used in the calculation of basic earnings per share	102,976,162	100,745,768

Diluted earnings per share

The earnings used in the calculation of diluted earnings per share does not differ from the earnings used in the calculation of basic earnings per share for the years ended December 31, 2018 and 2017. The weighted average number of common shares for the purposes of diluted earnings per share reconciles to the weighted average number of common shares used in the calculation of basic earnings per share as follows:

Year ended December 31	2018	2017
Weighted average number of common shares used in the calculation of basic earnings per share	102,976,162	100,745,768
Effect of dilutive share purchase options [2]	355,639	343,136
Weighted average number of common shares used in the calculation of diluted earnings per share	103,331,801	101,088,904

[2] For the years ended December 31, 2018 and December 31, 2017, the average market price of the Company's common shares was above the exercise price of certain granted share purchase options described in note 31 but had a neutral impact on earnings per share.

11. Impairment testing:

The Company reviews its CGUs that contain goodwill on an annual basis, in the third quarter, to determine whether any impairments should be recognized. As a result, the Company's East Windsor CGU was tested for impairment during the third quarter of 2018. The carrying amount of the East Windsor CGU was within the range of its estimated recoverable amount for both the 2018 and 2017 impairment tests and as such, no impairments were required for the East Windsor CGU. During the third quarter of 2017, the Company's East Windsor, Decatur Energy and Southport CGUs were tested for impairment.

Impairments recognized in the year ended December 31, 2017 were as follows:

	2017		
	Decatur Energy	Southport	Roxboro
Impairment of goodwill	$ 37	$ 21	$ N/A
Impairment of property, plant and equipment	N/A	11	14

As part of CPC's annual impairment testing in the third quarter of 2018, the Southport and Roxboro CGUs were assessed and there were no indications to test for a reversal of the previous impairments of property, plant and equipment.

11. Impairment testing, continued:

Impairment testing - 2018

Key assumptions – recoverable amount

The recoverable amount of the East Windsor CGU was determined based on its fair value less costs to sell, estimated using discounted cash flows. The fair value measurement of the East Windsor CGU is categorized in Level 3 of the fair value hierarchy based on the inputs used in the valuation model. The calculation of the recoverable amount is sensitive to several key assumptions as described below.

Discount rates

The after-tax discount rate used for the East Windsor CGU reflects the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to the East Windsor CGU. The method and assumptions used to calculate the WACC rate are generally consistent with the Company's past experience and previous valuations performed by the Company. The calculated WACC rate used for the East Windsor CGU impairment testing was 6% (2017 – 7%) which decreased from the rate used in the prior year's impairment testing based on peer market analysis, new market comparable transactions and adjustments pertaining to plant specific risk factors.

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures to the end of the East Windsor CGU's useful life. These estimates reflect past experience and the Company's current view of future generating capacity and fuel pricing. The Company has assumed the East Windsor PPA with the Ontario Independent Electricity System Operator will be extended for 20 years following the expiry of the current agreement in 2029 and re-contracted cash flow projections are based on the cost of generation for a new build. Consideration is given to externally available information related to future electricity contract rates and fuel inputs when developing assumptions and such external information is used to validate the Company's current view of future rates and costs. These external sources of information include information from third party advisory and research firms serving the industry.

Sensitivities for key cash flow assumptions

The recoverable amount for the East Windsor CGU approximates the carrying amount of the CGU, and as such, unfavourable changes to key cash flow assumptions would lead to an impairment of the CGU.

Impairment testing - 2017

During 2017, the uncertainty created by potential additional capital investment at the Southport and Roxboro facilities to meet more restrictive emissions standards triggered the Company to test the Roxboro CGU for impairment of its property, plant and equipment. These emissions standards are likely to render the Southport and Roxboro facilities uneconomic once the PPAs associated with those facilities expire in 2021.

Key assumptions – goodwill and indefinite life intangible assets recoverable amounts

The recoverable amounts of the Decatur Energy, Southport and Roxboro CGUs (the tested CGUs) were determined based on the higher of each CGUs respective fair value less costs to sell or value in use, estimated using discounted cash flows. The recoverable amount of the Decatur CGU was determined using a fair value less cost to sell approach and the recoverable amount of each of the other tested CGU's was determined using their respective values in use. The fair value measurements of the tested CGUs are categorized in Level 3 of the fair value hierarchy based on the inputs used in the valuation models. The calculations of the recoverable amounts for the tested CGUs are sensitive to several key assumptions as described below.

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

11. Impairment testing, continued:

Impairment testing – 2017, continued

Discount rates and growth rates

The after-tax discount rates used for the tested CGUs reflect the market WACC using a capital asset pricing model approach, giving consideration to the risks specific to each of the tested CGUs. The method and assumptions used to calculate the WACC rate are consistent with the Company's past experience and previous valuations performed by the Company. The calculated WACC rates used for impairment testing were in the range of 6% to 7%.

The Company projected cash flows for a period of ten years for the Decatur Energy CGU and used growth rates to extrapolate the cash flow projections beyond the ten-year period through to the end of the useful life of the Decatur Energy CGU. The growth rates reflect past experience, are consistent with industry practice and ranged between nil and 4% for the Decatur Energy CGU.

Other key cash flow assumptions

The Company's cash flow projections incorporate estimates of annual plant revenues, expenses and capital expenditures. These estimates reflect past experience and the Company's current view of future generating capacity, fuel mix, fuel pricing and expectations around cash flows following the currently contracted periods, for the tested CGU's.

The Company assumed that the Southport and Roxboro PPAs will not be extended following the expiry of the current PPAs and that the fuel mixes for the Southport and Roxboro facilities will be optimized at 55% wood waste, 35% tire-derived fuel, and 10% coal for the remainder of their respective PPA terms.

Consideration is given to externally available information related to future electricity contract rates and fuel inputs when developing assumptions and such external information is used to validate the Company's current view of future rates and costs. These external sources of information include information from third party advisory and research firms serving the industry.

12. Cash and cash equivalents:

As at December 31	2018	2017
Cash on deposit	$ 99	$ 29
Cash equivalents	83	23
	$ 182	$ 52

Cash and cash equivalents includes $63 million (2017 - $15 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 $48 million (2017 - $20 million).

13. Trade and other receivables:

As at December 31	2018	2017
Accrued revenues	$ 161	$ 99
Trade receivables	110	79
Finance lease receivables (note 16)	24	23
Net trade receivables	295	201
Proceeds on disposal of joint venture interest receivable (note 7)	90	-
Government grant receivable (note 17)	52	51
Income taxes recoverable	2	1
Prepayments	23	25
	$ 462	$ 278

Details of the aging of trade receivables and analysis of the movement on the allowance for doubtful accounts are provided in note 33.

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

14. Inventories:

As at December 31	2018	2017
Parts and other consumables	$ 105	$ 86
Emission credits	71	21
Coal	24	13
	$ 200	$ 120

Inventories expensed upon usage for the year ended December 31, 2018 of $149 million (2017 - $147 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 15. No write-downs in inventories were recognized in the year ended December 31, 2018 (2017 - nil). There were no reversals of previous write-downs recognized in the year ended December 31, 2018 (2017 - nil). As at December 31, 2018, no inventories were pledged as security for liabilities (2017 - nil).

15. Derivative financial instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purpose of energy purchases, merchant trading or financial risk management.

The derivative instruments assets and liabilities used for risk management purposes as described in note 33 consist of the following:

	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		138			
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	

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

15. Derivative financial instruments and hedge accounting, continued:

	December 31, 2017			
	Energy and emission allowances		Foreign exchange	
	cash flow hedges	non-hedges	non-hedges	Total
Derivative instruments assets:				
Current	$ 4	$ 47	$ 41	$ 92
Non-current	10	69	-	79
Derivative instruments liabilities:				
Current	(20)	(59)	(7)	(86)
Non-current	(10)	(44)	(2)	(56)
Net fair value	$ (16)	$ 13	$ 32	$ 29
Net notional buys (sells) (millions):				
Megawatt hours of electricity	(7)	(12)		
Gigajoules of natural gas		15		
Metric tons of emission allowances		1		
Number of renewable energy credits		(6)		
Cross-currency interest rate swaps (U.S. dollars) [1]			$ 195	
Forward currency sales (U.S. dollars) [1]			$ (80)	
Range of remaining contract terms in years [2]	0.1 to 4.0	0.1 to 13.2	1.4 to 1.9	

[1] The cross-currency interest rate swaps and forward currency sales of US$195 million were net settled on January 11, 2018 with a realized gain of $33 million.

[2] The remaining years of foreign exchange cash flow non-hedge contracts reflect US$115 million in forward currency buys.

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, 2018 and, 2017, the Company classified financial instruments under Level 2 and Level 3 of the fair value hierarchy described in note 3.

The Company has previously elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings and currency risk relating to U.S. dollar denominated loans and borrowings. As a result of the Decatur Energy acquisition and the repayment of certain foreign currency loans and borrowings during the third quarter of 2017, the foreign currency exposure, that was previously hedged by a cross-currency interest rate swap, no longer existed.

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

15. Derivative financial instruments and hedge accounting, continued:

As a result, the Company de-designated the cross-currency interest rate swap as a foreign exchange cash flow hedge during the third quarter of 2017. The gains associated with the cross-currency interest rate swap, up until the time of de-designation, had previously been reclassified from other comprehensive loss to net income and as a result, upon de-designation no further reclassification is required.

The Company had previously elected to apply hedge accounting on certain derivative financial instruments whereby the Company entered into swap agreements with third parties to swap the market revenues earned on Bloom Wind and New Frontier Wind generation for a fixed annual payment on Bloom Wind and a fixed price per megawatt hour (MWh) on New Frontier Wind. Bloom Wind transactions were to be settled using proxy generation and the Southwest Power Pool (SPP) North Hub reference price. To determine the fair value of the Bloom Wind swap and support hedge effectiveness testing, forward prices of the SPP North Hub and the Bloom Wind Node were required, however quoted forward market prices for the SPP North Hub were limited to two years in the future with forward prices unavailable. Since Bloom Wind's commercial operation date in June 2017, actual captured basis (the difference between the SPP North Hub and Bloom Wind Node pricing) has exceeded the expected basis differential and changes to the Bloom Wind Node price have not been as closely aligned to changes in the SPP North Hub price as previously expected. With this additional information, management has revised the forward price methodology to more accurately reflect the Bloom Wind Node price dynamics resulting in the Bloom Wind swap no longer meeting the hedge effectiveness criteria. Based on the revised methodology for Bloom Wind, management now expects New Frontier Wind to function in a similar manner to Bloom Wind post commercial operation date. As a result, effective October 30, 2017, the Company de-designated the swap agreements relating to both Bloom Wind and New Frontier Wind as cash flow hedges. Since the forecasted transactions are still expected to occur, the fair value recognized in accumulated other comprehensive income will remain and fair value adjustments subsequent to ineffectiveness will be recognized in net income. The balance in accumulated other comprehensive income will be reclassified to net income in future periods as generation occurs at the respective nodes.

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

	2018		2017	
	Unrealized gains (losses)	Realized (losses) gains	Unrealized (losses) gains	Realized gains (losses)
Energy cash flow hedges	$ 47	$ (19)	$ (94)	$ 86
Energy and emission allowances non-hedges	(70)	68	(34)	61
Interest rate cash flow hedges	(7)	-	-	-
Foreign exchange cash flow hedges [3]	-	-	(58)	2
Foreign exchange non-hedges	(21)	34	32	(13)

[3] For the year ended December 31, 2018, realized gains of $3 million related to the foreign exchange cash flow hedges for the Arlington facility acquisition (see note 4) were reclassified from net income and applied to the Canadian dollar balances of the acquired assets and assumed liabilities. For the year ended December 31, 2017, unrealized losses of $24 million related to foreign exchange cash flow hedges were reclassified from other comprehensive income to net income to offset the impact of unrealized foreign exchange gains and losses from the revaluation of U.S. dollar denominated loans and borrowings.

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 (loss) for the years ended December 31, 2018 and 2017:

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

15. Derivative financial instruments and hedge accounting, continued:

	2018	2017
Revenues	$ 55	$ 131
Energy purchases and fuel	(76)	(18)
Foreign exchange gain (loss)	13	(37)

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity prices, interest rate risk relating to future borrowings and currency risk relating to U.S. dollar denominated loans and borrowings and U.S. dollar acquisition payments. For the year ended December 31, 2018, there were no changes in the fair value of the ineffective portion of hedging derivatives required to be recognized in the statement of income (2017 – gains of $2 million).

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

As at December 31	2018
Within one year	$ (5)
Between one and five years	11
After five years	8
	$ 14

The amounts in the table above include the reclassification to net income, of net gains recorded within accumulated other comprehensive income, pertaining to the New Frontier Wind and Bloom Wind swap agreements which were de-designated as cash flow hedges effective October 30, 2017.

16. Leases:

Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2018	2017	2018	2017
Amounts receivable under finance leases:				
Less than one year	$ 57	$ 57	$ 24	$ 23
Between one and five years	228	229	110	104
More than five years	697	754	510	540
Unearned finance income	(338)	(373)	-	-
Lease payments receivable	644	667	644	667
Less current portion: (included within trade and other receivables (note 13)	24	23	24	23
	$ 620	$ 644	$ 620	$ 644

The PPAs pertaining to the Company's wind generation facilities located in Ontario (Kingsbridge 1 and Port Dover and Nanticoke) and British Columbia (Quality Wind) are finance leases and expire in 2026, 2033 and 2037 respectively and have effective rates inherent in the leases of 3.21%, 6.16% and 4.86% respectively. The lease receivables contain unguaranteed residual values of $13 million, $44 million and nil for the Kingsbridge, Port Dover and Nanticoke and Quality Wind facilities respectively.

Details of the fair value of the finance lease receivables are provided in note 32.

Finance income of $34 million was recognized in revenues during the year ended December 31, 2018 (2017 - $35 million).

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

16. Leases, continued:

Finance lease obligation

	Minimum lease payments		Present value of minimum lease payments	
As at December 31	2018	2017	2018	2017
Amounts payable under finance leases:				
Less than one year	$ 2	$ 2	$ 1	$ 1
Between one and five years	8	7	5	4
More than five years	13	14	12	13
Interest costs	(5)	(5)	-	-
Lease obligation	18	18	18	18
Less current portion: (included within trade and other payables (note 22)	1	1	1	1
	$ 17	$ 17	$ 17	$ 17

Details of the assets under finance lease are provided in note 20.

Details of the fair value of the finance lease obligation are provided in note 32.

Interest expense pertaining to the finance lease obligation of $1 million was recognized in net finance expense during the year ended December 31, 2018 (2017 - $1 million).

Facilities under operating leases

Certain power generation facilities owned by the Company operate under PPAs that convey the right to the holder of the agreement to use the related property, plant and equipment. Consequently, the Roxboro, Genesee units 1 and 2, Island Generation, Decatur Energy, East Windsor, EnPower and Arlington power generation facilities are accounted for as assets under operating leases.

As at December 31, 2018, the cost of such property, plant and equipment was $2,512 million (2017 - $2,017 million), less accumulated depreciation of $724 million (2017 - $506 million).

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

As at December 31	2018
Within one year	$ 214
Between one and five years	508
After five years	271
	$ 993

17. Government compensation:

On November 24, 2016, the Company announced details of the agreement reached 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 will be 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. 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.

Additional conditions include the Company supporting the local communities surrounding the coal facilities through 2030, and fulfilling its pension and other commitments to employees.

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

17. Government compensation, continued:

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 and 2018 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 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.

18. Deferred tax:

Movement of deferred tax balances

	As at January 1, 2018	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, 2018	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 78	$ (1)	$ 4	$ -	$ 16	$ (18)	$ 79	$ 79	$ -
Property, plant and equipment	(348)	(75)	(4)	3	-	-	(424)	-	(424)
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	-
Finance lease receivables	(180)	6	-	-	-	-	(174)	-	(174)
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 assets (liabilities)	$ (300)	$ (75)	$ (10)	$ -	$ 27	$ (18)	$ (376)	$ 485	$ (861)
Set-off of tax							-	(426)	426
Net deferred tax assets (liabilities)							$ (376)	$ 59	$ (435)

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

18. Deferred tax, continued:

Movement of deferred tax balances, continued

	As at January 1, 2017	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, 2017	Deferred tax assets	Deferred tax liabilities
Losses carried forward	$ 26	$ 57	$ (4)	$ -	$ 13	$ (14)	$ 78	$ 78	$ -
Property, plant and equipment	(288)	(38)	1	(23)	-	-	(348)	-	(348)
Intangible assets	44	-	-	(1)	-	-	43	46	(3)
Deferred partnership income	9	(13)	-	(2)	-	-	(6)	-	(6)
Derivative financial instruments	(41)	13	28	-	-	-	-	31	(31)
Share issue costs and deferred financing charges	2	(3)	-	-	3	-	2	3	(1)
Equity-accounted investments	(8)	3	(2)	-	-	-	(7)	-	(7)
Deferred revenue and other liabilities	191	(8)	(1)	-	-	-	182	182	-
Finance lease receivables	(186)	6	-	-	-	-	(180)	-	(180)
Government grant receivable	(160)	13	-	-	-	-	(147)	-	(147)
Other financial assets	(14)	-	-	-	-	-	(14)	-	(14)
Decommissioning provisions	55	4	(1)	3	-	-	61	61	-
Goodwill	(8)	17	-	-	-	-	9	9	-
Prepaid reclamation amounts	(19)	1	-	-	-	-	(18)	-	(18)
Other provisions	11	7	1	-	-	-	19	19	-
Loans and borrowings	16	(2)	-	5	-	-	19	19	-
Other assets	7	-	-	-	-	-	7	7	-
Deferred tax assets (liabilities)	$ (363)	$ 57	$ 22	$ (18)	$ 16	$ (14)	$ (300)	$ 455	$ (755)
Set-off of tax							-	(381)	381
Net deferred tax assets (liabilities)							$ (300)	$ 74	$ (374)

Unrecognized deferred tax assets

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

As at December 31	2018	2017
Non-capital losses	$ 72	$ 94
Deductible temporary differences with no expiry	82	51
	$ 154	$ 145

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

18. Deferred tax, continued:

Tax losses carried forward

	2018		2017	
	Tax losses	Expiry dates	Tax losses	Expiry dates
Unrecognized tax losses carried forward	$ 72	2028-2038	$ 94	2028-2037

As at December 31, 2018, the Company has non-capital losses carried forward of $410 million (2017 - $399 million), of which $310 million (US$227 million) (2017 - $268 million (US$214 million)) relates to U.S. subsidiaries.

The deferred tax assets presented on the consolidated statements of financial position are recoverable based on estimated future net income and the reversal of taxable temporary differences. The assumptions used in the estimate of future net income are based on the Company's cash flow projections, which include the estimates described in note 11.

19. Intangible assets:

	Intangible work in progress	PPAs	Contract rights	Other rights	Emission credits	Software	Total
Cost							
As at January 1, 2017	$ 29	$ 11	$ 41	$ 164	$ 61	$ 53	$ 359
Additions	16	-	-	-	68	-	84
Additions from business acquisitions (note 4)	-	47	-	-	-	-	47
Additions into service	(14)	-	8	4	-	2	-
Transfers to property, plant and equipment (note 20)	-	-	-	(2)	-	-	(2)
Foreign currency translation adjustments	(2)	(3)	-	(1)	-	-	(6)
As at December 31, 2017	$ 29	$ 55	$ 49	$ 165	$ 129	$ 55	$ 482
Additions	53	-	-	-	5	-	58
Additions from business acquisition (note 4)	-	102	-	11	-	-	113
Additions into service	(28)	-	-	28	-	-	-
Retirements and other disposals	-	-	-	-	(63)	-	(63)
Transfers to held for sale emission credits inventories	-	-	-	-	(24)	-	(24)
Foreign currency translation adjustments	3	7	1	2	-	-	13
As at December 31, 2018	$ 57	$ 164	$ 50	$ 206	$ 47	$ 55	$ 579
Accumulated amortization							
As at January 1, 2017	$ -	$ (7)	$ (9)	$ (18)	$ -	$ (26)	$ (60)
Amortization (note 6)	-	(5)	(2)	(8)	-	(6)	(21)
As at December 31, 2017	$ -	$ (12)	$ (11)	$ (26)	$ -	$ (32)	$ (81)
Amortization (note 6)	-	(8)	(3)	(8)	-	(5)	(24)
Foreign currency translation adjustments	-	(1)	-	-	-	-	(1)
As at December 31, 2018	$ -	$ (21)	$ (14)	$ (34)	$ -	$ (37)	$ (106)
Net book value							
As at January 1, 2017	$ 29	$ 4	$ 32	$ 146	$ 61	$ 27	$ 299
As at December 31, 2017	$ 29	$ 43	$ 38	$ 139	$ 129	$ 23	$ 401
As at December 31, 2018	$ 57	$ 143	$ 36	$ 172	$ 47	$ 18	$ 473

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

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

19. Intangible assets, continued:

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 and pipeline access rights relating to the Arlington facility.

Impairments

No impairments of intangible assets were recognized during the year ended December 31, 2018 (2017 - nil). No previous impairments of intangible assets were reversed during the year ended December 31, 2018 (2017 - nil).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the years ended December 31, 2018 or 2017.

Restrictions on assets

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

20. Property, plant and equipment:

	Construction work in progress	Land	Plant and equipment	Total
Cost				
As at January 1, 2017	$ 253	$ 116	$ 4,385	$ 4,754
Additions	188	-	-	188
Additions into service	(382)	-	382	-
Retirements and other disposals	-	-	(57)	(57)
Acquisitions through business combinations (note 4)	5	2	741	748
Impairments (note 11)	-	-	(25)	(25)
Transfers from intangible assets (note 19)	-	-	2	2
Other transfers	1	-	-	1
Revisions to decommissioning costs (note 26)	-	-	15	15
Foreign currency translation adjustments	(1)	-	(74)	(75)
As at December 31, 2017	$ 64	$ 118	$ 5,369	$ 5,551
Additions	297	1	13	311
Additions into service	(232)	-	232	-
Retirements and other disposals	-	-	(58)	(58)
Acquisition through business combination (note 4)	6	3	287	296
Transfers to inventory	(4)	-	-	(4)
Revisions to decommissioning costs (note 26)	-	-	3	3
Foreign currency translation adjustments	5	-	105	110
As at December 31, 2018	$ 136	$ 122	$ 5,951	$ 6,209
Accumulated depreciation				
At January 1, 2017	$ -	$ -	$ (990)	$ (990)
Depreciation (note 6)	-	-	(249)	(249)
Retirements and other disposals	-	-	57	57
Foreign currency translation adjustments	-	-	9	9
As at December 31, 2017	$ -	$ -	$ (1,173)	$ (1,173)
Depreciation (note 6)	-	-	(274)	(274)
Retirements and other disposals	-	-	58	58
Foreign currency translation adjustments	-	-	(17)	(17)
As at December 31, 2018	$ -	$ -	$ (1,406)	$ (1,406)
Net book value				
As at January 1, 2017	$ 253	$ 116	$ 3,395	$ 3,764
As at December 31, 2017	$ 64	$ 118	$ 4,196	$ 4,378
As at December 31, 2018	$ 136	$ 122	$ 4,545	$ 4,803

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

20. Property, plant and equipment, continued:

Asset under finance lease

As at December 31, 2018, the asset under finance lease had a net book value of $16 million (2017 – $17 million) and the Company recorded depreciation expense of $2 million during the year ended December 31, 2018 (2017 – $2 million).

Impairments

No impairments of property, plant and equipment were recognized during the year ended December 31, 2018 (2017 - $11 million and $14 million related to the Company's Southport and Roxboro CGUs, respectively). No reversals of impairments on property, plant and equipment were recognized during the year ended December 31, 2018 (2017 - 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 4.45% (2017 – 4.83%) for projects financed using general borrowings. For the years ended December 31, 2018 and 2017, 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 23.

21. Goodwill:

	2018	2017
Cost and net book value		
As at January 1	$ 35	$ 23
Additions from business acquisitions (note 4)	-	77
Foreign currency translation adjustments	-	(7)
Impairments (note 11)	-	(58)
As at December 31	$ 35	$ 35

The aggregate carrying amount of goodwill as at December 31, 2018 and 2017 is related to the Company's East Windsor CGU.

Impairments

There were no pre-tax impairments of goodwill for the year ended December 31, 2018 (2017 – $58 million) as disclosed in note 11.

22. Trade and other payables:

As at December 31	2018	2017
Operating accruals	$ 122	$ 103
Trade payables	57	38
Dividends payable	46	44
Accrued interest	15	19
Finance lease obligation (note 16)	1	1
Taxes payable	4	11
	$ 245	$ 216

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

23. Loans and borrowings:

	Effective interest rate	December 31, 2018	December 31, 2017
Unsecured senior medium-term notes, payable semi-annually			
Issued by CPC, at 4.85% due in 2019	4.96%	$ 250	$ 250
Issued by CPC, at 5.28% due in 2020	5.34%	300	300
Issued by CPC, at 4.28% due in 2024	4.37%	450	450
		1,000	1,000
CPC private placement, payable semi-annually			
Issued by CPC, at 3.85% due in 2026	3.85%	160	160
		160	160
CPLP unsecured senior debt, payable annually to EPCOR			
At 5.80% repaid in 2018	5.63%	-	163
At 9.00% repaid in 2018	7.41%	-	11
		-	174
CPLP unsecured senior notes, payable semi-annually			
US$230, at 5.21% due in 2021	5.29%	314	289
US$65, at 5.61% due in 2026	5.67%	89	81
		403	370
CPLP non-recourse financing, payable quarterly			
Joffre Cogeneration Project, at 8.59%, due in 2020	8.31%	9	14
East Windsor Cogeneration Project, at 6.28%, due in 2029	6.23%	138	148
Macho Springs, US$50 at 6.90%, due in 2031	7.00%	59	57
		206	219
Tax-equity financing, payable quarterly [1]			
Macho Springs		-	3
Bloom Wind, US$113		155	206
New Frontier Wind, US$95		130	-
Committed credit facilities			
CPLP US$160, at floating rates, due in 2023	5.10%	218	-
CPC, at floating rates, due 2019 to 2023	3.61%	396	
CPLP US$100, at floating rates, repaid in 2018	3.80%	-	28
Joffre Cogeneration Project at floating rates, repaid in 2018	4.45%	-	4
		899	241
Total debt payable		2,668	2,164
Less: current portion		456	239
		2,212	1,925
Less: deferred debt issue costs		21	18
		$ 2,191	$ 1,907

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

23. Loans and borrowings, continued:

Medium-term note issuance

On September 18, 2017, the Company issued $450 million of unsecured medium-term notes due in 2024 with interest payable semi-annually at 4.284% commencing on March 18, 2018.

Non-recourse financing

Joffre Cogeneration Project financing represents the Company's share of syndicated loans for the project. The debt is secured by a charge against project assets which have a carrying amount of $50 million.

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 $154 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 $83 million.

Tax-equity financing

Macho Springs, 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. The maturity of Macho Springs tax-equity financing occurred in the third quarter of 2018.

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. The Company anticipates the maturity date of the New Frontier Wind tax-equity financing will occur in 2028 to coincide with the period that the project will benefit from the Production Tax Credits.

On June 1, 2017, the Company commenced commercial operation of Bloom Wind. On June 12, 2017, the Company received $244 million (US$181 million) in financing from an affiliate of Goldman Sachs in exchange for Class A interests of a subsidiary of the Company. The Company incurred issue costs of $7 million (US$5 million) associated with the financing. The Company anticipates the maturity date of the Bloom Wind tax-equity financing will occur in 2028 to coincide with the period that the project will benefit from the Production Tax Credits.

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, 2023. As at December 31, 2018, the Company had Canadian loans of $246 million (2017 – nil), U.S. loans of $218 million (US$160 million) (2017 - $28 million (US$23 million)) and letters of credit of $99 million (2017 - $30 million) outstanding under these facilities as described in note 38.

Bilateral unsecured demand credit facilities are available to CPC and include $200 million for the issuance of letters of credit and a further $20 million general facility. An additional $150 million bilateral credit facility is available to CPC maturing in 2019. As at December 31, 2018, $150 million has been drawn on these facilities (2017 – nil), and letters of credit of $172 million (2017 – $139 million) have been issued as described in note 38.

The Company has a bilateral unsecured $5 million demand facility available which is undrawn at December 31, 2018 (2017 – nil).

Under the terms of the extendible 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)

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

	Total loans and borrowings[1]	Finance lease obligation[2]
As at January 1, 2018	$ 2,146	$ 18
Changes from financing cash flows:		
Proceeds from issue of loans and borrowings[3]	705	-
Repayments	(195)	(1)
Deferred debt issue costs	(6)	-
Total changes from financing cash flows	504	(1)
Effect of changes in foreign exchange rates	63	1
Non-cash repayments on tax-equity financing	(80)	-
Implicit interest on tax-equity financing	16	-
Investment in non-controlling interests	(2)	-
Total other changes	(3)	1
As at December 31, 2018	$ 2,647	$ 18

[1] Includes deferred debt issue costs.

[2] Includes the current portion disclosed within trade and other payables.

[3] Proceeds from issue of loans and borrowings include the increase and use of additional committed credit facilities, the use of existing credit facilities and New Frontier Wind project equity financing described in note 23.

25. Deferred revenue and other liabilities:

As at December 31	2018	2017
Deferred government grant revenue (note 17)	$ 505	$ 539
Other deferred revenue and liabilities	143	100
	648	639
Less current portions:		
Deferred government grant revenue	50	50
Other deferred revenue and liabilities	11	8
Total current deferred revenue and other liabilities	61	58
	$ 587	$ 581

26. Provisions:

As at December 31	2018	2017
Decommissioning	$ 259	$ 228
Employee benefits [1]	74	62
Other [2]	12	12
	345	302
Less: current portion	54	37
	$ 291	$ 265

[1] Included in the employee benefits provision is $24 million pertaining to the share-based payment obligations described in note 31, of which $24 million is vested at December 31, 2018 (2017 - $17 million total share-based payment obligation, $17 million vested).

[2] Included in other current provisions as at December 31, 2018 is $9 million (2017 – $9 million) pertaining to the Line Loss Rule (LLR) proceeding as described in note 37(e).

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

26. Provisions, continued:

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2017	$ 195	$ 57	$ 5	$ 257
Additional liabilities incurred [3]	9	26	12	47
Liabilities assumed in business combinations	13	-	-	13
Liabilities settled	(3)	(20)	-	(23)
Amounts reversed unused	(2)	(1)	(5)	(8)
Foreign currency translation adjustments	(3)	-	-	(3)
Revisions to decommissioning costs (note 20)	15	-	-	15
Unwinding of the discount (note 8)	4	-	-	4
As at December 31, 2017	$ 228	$ 62	$ 12	$ 302
Additional liabilities incurred	12	31	-	43
Liabilities assumed in business combination (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 20)	3	-	-	3
Unwinding of the discount (note 8)	5	-	-	5
As at December 31, 2018	$ 259	$ 74	$ 12	$ 345

[3] Included in other additional liabilities incurred during the year ended December 31, 2017 is $9 million pertaining to the Line Loss Rule (LLR) proceeding as described in note 37(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, 2018, the Company's estimate of the undiscounted cash flow required to settle its decommissioning obligations is approximately $421 million (2017 - $377 million), calculated using an inflation rate of 2% (2017 – 2%). The expected timing for settlement of the obligations is between 2019 and 2055, which reflects ongoing reclamation of areas of the Genesee Coal Mine and the anticipated useful lives of the different power generation facilities.

The majority of the payments to settle the obligations are expected to occur between 2031 and 2045 for the power generation facilities and between 2019 and 2027 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 1.97% to 3.03%. 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.

27. 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
Special limited voting share	one

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

27. Share capital, continued:

Issued and fully paid shares

	Common shares			Preference shares		
	Number of shares		Amount	Number of shares		Amount
As at January 1, 2017	96,152,416	$	2,258	27,000,000	$	660
Shares issued	7,375,000		183	6,000,000		150
Share issue costs	-		(7)	-		(4)
Deferred taxes on share issue costs (note 18)	-		2	-		1
Share purchase options exercised (note 31)	786,677		19	-		-
As at December 31, 2017	104,314,093	$	2,455	33,000,000	$	807
Share purchase options exercised (note 31)	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

[1] During the year ended December 31, 2018, the Company purchased and canceled 2,987,182 of its outstanding common shares at an average exercise price of $25.28 per share for $76 million under its Toronto Stock Exchange approved normal course issuer bid. During the year ended December 31, 2017, the Company did not purchase and cancel any of its outstanding common shares.

On April 24, 2017, the Company announced the completion of its public offering of 7,375,000 subscription receipts (Subscription Receipts), on a bought deal basis, at an issue price of $24.75 per Subscription Receipt, for total gross proceeds of $183 million less issue costs of $7 million. On June 13, 2017, upon closing of the Decatur Energy acquisition, each Subscription Receipt was converted for one common share of the Company. No dividend record date occurred during the period when the Subscription Receipts were outstanding and as such, no obligations to make any cash dividend equivalent payments were triggered.

On August 9, 2017, the Company issued 6 million Cumulative Minimum Rate Reset Preference Shares, Series 9 (Series 9 Shares) at a price of $25.00 per share for gross proceeds of $150 million less issue costs of $4 million. The Series 9 Shares are redeemable by Capital Power, at its option on September 30, 2022 and every five years thereafter at a value of $25.00 per share.

Holders of the Series 9 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 10 (Series 10 Shares), subject to certain conditions, as disclosed in the Cumulative rate reset preference shares table below.

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 2019, 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.

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

27. Share capital, continued:

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.
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 would be 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.

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

27. 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 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.

[2] Holders of Series 1, Series 3, Series 5, Series 7, and Series 9 shares will be entitled to receive fixed cumulative quarterly dividends that yield 3.06%, 5.45%, 5.24%, 6.00%, 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 and Series 10 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% and 4.12% respectively, as and when declared by the board of directors of Capital Power.

The common and preferred share dividends declared and paid by the Company for the years ended December 31, 2018 and 2017 are summarized as follows:

	Dividends declared				Dividends paid			
	2018		2017		2018		2017	
	Per share	Total	Per share	Total	Per share	Total	Per share	Total
Common [4]	$ 1.7300	$ 178	$ 1.6150	$165	$ 1.7000	$176	$ 1.5875	$159
Preference, Series 1	0.7650	4	0.7650	4	0.7650	4	0.7650	4
Preference, Series 3	1.1500	7	1.1500	7	1.1500	7	1.1500	7
Preference, Series 5	1.2173	10	1.1250	9	1.2173	10	1.1250	9
Preference, Series 7	1.5000	12	1.5000	12	1.5000	12	1.5000	12
Preference, Series 9	1.4375	8	0.5642	3	1.4375	8	0.5642	3

[4] On July 27, 2018, the Company's Board of Directors approved an increase of 7% in the annual dividend to $1.79 per common share effective for the third quarter of 2018.

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

28. Other reserves:

Components of other comprehensive income (loss) and other reserves are established as follows:

Cash flow hedges

The cash flow hedging reserve represents the cumulative portion of gains and losses on hedging instruments deemed effective in cash flow hedges. The cumulative deferred gains or losses on the hedging instrument are reclassified to net income or loss only when the hedged transaction affects the net income or loss, or are included as a basis adjustment to the non-financial hedged item, consistent with the relevant accounting policy.

Cumulative translation reserve

The cumulative translation reserve for foreign operations represents the cumulative portion of gains and losses on retranslation of foreign operations that have a functional currency other than Canadian dollars. The cumulative deferred gain or loss on the foreign operation is reclassified to net income or loss only on disposal of the foreign operation.

Defined benefit plan actuarial gains and losses

The defined benefit plan actuarial gains and losses represent the cumulative differences between actual and expected experience and from changes in actuarial assumptions used to determine the accrued benefit obligation.

Employee benefits reserve

The equity-settled employee benefits reserve reflects share options granted to employees under the employee share option plan. Information about share-based payments to employees is disclosed in note 31.

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

Other cash items

Year ended December 31	2018	2017
Miscellaneous financing fees paid	$ (6)	$ (5)
Reclamation costs	(3)	(3)
Income taxes paid	(2)	(2)
Other	(11)	(6)
	$ (22)	$ (16)

Change in non-cash operating working capital

Year ended December 31	2018	2017
Trade and other receivables	$ (78)	$ (26)
Inventories	(37)	4
Trade and other payables	66	(14)
Deferred revenue and other liabilities	(1)	-
Provisions	7	(4)
	$ (43)	$ (40)

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

30. Related party balances and transactions:

Nature of transactions

As described in note 36, 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.

Compensation of key management personnel

Year ended December 31	2018	2017
Short-term employee benefits	$ 6	$ 5
Share-based payments	5	4
	$ 11	$ 9

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

31. 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 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.

In March 2017, the Company granted 696,057 share purchase options with one third vesting on March 9 of each of 2018, 2019 and 2020. The fair values of these options at grant date were $2.04, $2.08 and $2.11 per option for the 2018, 2019 and 2020 tranches respectively. Granted options may be exercised within 7 years of the grant date at a price of $25.53 per share.

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

	Share purchase options issued in:	
	2018	2017
Share price at grant date	$ 24.47	$ 25.53
Expected volatility [1]	17.30%	17.90%
Expected option life [2]	4.5 years	4.5 years
Expected dividend yield	6.60%	5.92%
Risk-free interest rate [3]	1.84%	1.12%
Exercise price	$ 24.47	$ 25.53
Expiry date	March 7, 2025	March 9, 2024

[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)

31. Share-based payments, continued:

Share purchase options, continued

The following illustrates the movements on share purchase options during the years ended December 31, 2018 and 2017:

	2018		2017	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Options outstanding, as at January 1	3,957,502	$ 22.94	4,126,912	$ 22.46
Granted	719,050	24.47	696,057	25.53
Exercised [4]	(545,707)	23.25	(786,677)	22.84
Forfeited	(70,711)	23.58	(77,212)	22.02
Expired	(482,474)	24.83	(1,578)	25.53
Options outstanding, as at December 31	3,577,660	$ 22.93	3,957,502	$ 22.94
Vested options outstanding, as at December 31	2,164,726	$ 22.68	2,491,804	$ 23.48

[4] The weighted average share price at the date of exercise was $27.09 (2017 - $25.62).

During the year ended December 31, 2018, the Company recorded compensation expense of $1 million related to share purchase options in staff costs and employee benefits expense (year ended December 31, 2017 – $1 million).

The weighted average remaining contractual life of the Company's outstanding share purchase options as at December 31, 2018 is 3.78 years (2017 – 3.53 years). The exercise prices of share purchase options outstanding as at December 31, 2018 range from $17.33 to $25.53 (2017 - $17.33 to $25.53).

Performance share units

Capital Power grants performance share units (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.

	2018	2017
PSUs outstanding, as at January 1	355,220	331,859
Granted [5]	113,758	104,408
Released [6]	(88,054)	(110,764)
Dividends reinvested	28,657	42,761
Forfeited	(28,719)	(13,044)
PSUs outstanding, as at December 31	380,862	355,220

[5] The fair value of the PSUs at the grant date was $23.34 (2017 - $24.71).

[6] The weighted average share price at the date of release was $24.26 (2017 - $23.15).

During the year ended December 31, 2018, the Company recorded a compensation expense of $8 million (2017 – $5 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)

31. Share-based payments, continued:

Restricted share units

Capital Power grants restricted share units (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.

	2018	2017
RSUs outstanding, as at January 1	310,212	310,568
Granted [7]	96,713	96,675
Released [8]	(93,187)	(94,061)
Dividends reinvested	20,785	20,206
Forfeited	(25,443)	(23,176)
RSUs outstanding, as at December 31	309,080	310,212

[7] The fair value of the RSUs at the grant date was $23.34 (2017 – $24.71).

[8] The weighted average share price at the date of release was $24.26 (2017 – $23.19).

During the year ended December 31, 2018, the Company recorded a compensation expense of $3 million (2017 – $3 million) related to the outstanding RSUs in staff costs and employee benefits expense.

Deferred share units

The Company has approved a deferred share unit (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 TSX for the five trading days immediately before the redemption date. During the year ended December 31, 2018, the Company recorded a compensation expense of $2 million (2017 – $2 million) related to the outstanding DSUs in staff costs and employee benefits expense.

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

32. 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 15.

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

		December 31, 2018		December 31, 2017	
	Fair value hierarchy level	Carrying amount	Fair value	Carrying amount	Fair value
Financial assets [1]					
Finance lease receivables (note 16)	Level 2	644	723	667	757
Government grant receivable (note 17)	Level 2	511	505	544	544
Financial liabilities [1]					
Loans and borrowings (note 23)	Level 2	2,647	2,645	2,146	2,203
Finance lease obligation (note 16)	Level 2	18	18	18	18

[1] Includes current portion

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

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Derivative financial instruments assets	$ -	$ 139	$ 32	$ 171
Derivative financial instruments liabilities	-	(140)	(2)	(142)

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

32. Financial instruments, continued:

Fair value hierarchy, continued

Valuation techniques used in determination of fair values within Level 3

The following financial instruments are classified within Level 3 of the hierarchy as forward market prices are not available for the full period of the contracts which extend beyond a liquid trading period, and as such their fair values are derived using forecasts based on internal modelling.

- On April 30, 2018, the Company entered into a 12-year contract to swap the market price per megawatt hour (MWh) for a fixed price per MWh for 85% of the notional generation of its Cardinal Point Wind project (Cardinal Point Wind).
- On August 30, 2017, the Company entered into a 12-year contract to swap the market price per MWh for a fixed price per MWh for 87% of the notional generation of its New Frontier Wind project (New Frontier Wind).
- On April 21, 2016, the Company entered into a 10-year, fixed price contract to swap the market revenue from Bloom Wind generation for a fixed annual payment for a 10-year term.

In addition, as at December 31, 2018 and December 31, 2017, the Company holds contracts for the sale of RECs for which pricing beyond two years is not readily observable and 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	2018	2017
REC pricing (per certificate) – Thermal	$1.09	$0.80 to $0.86
REC pricing (per certificate) – Solar	$221.55 to $395.64	$200.05 to $348.25
Power pricing (per MWh) – Wind	$15.48 to $70.68	$16.75 to $35.64

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 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	2018	2017
REC pricing – Thermal [2]	$ -	$ 1
REC pricing – Solar [2]	-	-
Power pricing – Wind [2]	17	12

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

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:

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

32. Financial instruments, continued:

Fair value hierarchy, continued

Continuity of Level 3 balances, continued

	2018	2017
As at January 1 [3]	$ 30	$ (10)
Unrealized and realized (losses) gains included in net income [4]	(55)	8
Unrealized gains included in other comprehensive income	-	32
Settlements [5]	-	2
Transfers [6]	(5)	(2)
Foreign exchange gain	2	-
As at end of period	$ (28)	$ 30
Total unrealized gains for the period included in other comprehensive income	$ -	$ 32
Total unrealized and realized (losses) gains for the period included in net income [4]	$ (55)	$ 10

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

[4] Recorded in revenues.

[5] Relates to settlement of financial derivative instruments.

[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 values of the Company's finance lease receivables and government grant receivable held at amortized cost are estimated by discounting the expected future cash flows of these instruments 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, 2018 and 2017.

Financial liabilities

The fair values of the Company's loans and borrowings and finance lease obligation are based on determining a current yield for the Company's loans and borrowings as at December 31, 2018 and 2017. 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 (ISDA) 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)

32. 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

As at December 31, 2018

				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
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 $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

As at December 31, 2018

				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
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 $82 million, non-current derivative instruments liabilities of $114 million and trade and other payables of $37 million.

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

32. Financial instruments, continued:

Offsetting of financial assets and liabilities, continued

Financial assets subject to offsetting, enforceable master netting arrangements or similar arrangements, continued

As at December 31, 2017

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 [10]	Related amounts not offset in the statement of financial position: Financial instruments	Related amounts not offset in the statement of financial position: Collateral received [11]	Net amount
Commodity trading assets	$ 178	$ (15)	$ 163	$ (77)	$ (5)	$ 81

[10] The net amounts of commodity trading assets presented in the statement of financial position include current derivative instruments assets of $51 million, non-current derivative instruments assets of $79 million and trade and other receivables of $33 million.

[11] 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

As at December 31, 2017

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 [12]	Related amounts not offset in the statement of financial position: Financial instruments	Related amounts not offset in the statement of financial position: Collateral pledged	Net amount
Commodity trading liabilities	$ 167	$ (15)	$ 152	$ (83)	$ (23)	$ 46

[12] The net amounts of commodity trading liabilities presented in the statement of financial position include current derivative instruments liabilities of $79 million, non-current derivative instruments liabilities of $54 million and trade and other payables of $19 million.

33. Risk management:

Risk management overview

The Company is exposed to a number of different 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.

33. Risk management, continued:

Risk management overview, continued

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.

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.

33. Risk management, continued:

Market risk, continued

Commodity price risk, continued

The fair value of the Company's energy related derivatives as at December 31, 2018, that are required to be measured at fair value with the respective changes in fair value recognized in net income are disclosed in note 15.

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 2019, as at December 31, 2018, 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.

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, 2018, the VaR of the Company's commodity trading and assets portfolios for 2019 as a result of unfavourable market price changes is $21 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

33. Risk management, continued:

Market risk, continued

Foreign exchange risk, continued

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, 2018, the Company held foreign exchange derivatives as disclosed in note 15.

As at December 31, 2018, holding all other variables constant, a $0.10 strengthening or weakening of the Canadian dollar against the U.S. dollar would have decreased or increased net income attributable to shareholders by $10 million (2017 – decreased or increased by $9 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.

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. In some circumstances, floating rate funding may be used for current borrowings and other liquidity requirements. As at December 31, 2018, the proportion of fixed rate loans and borrowings was approximately 77% of total loans and borrowings outstanding (2017 - 98%). The Company may also use derivative instruments to manage interest rate risk. At December 31, 2018, the Company held interest rate derivatives as disclosed in note 15 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 remains at 77% as at December 31, 2018. As at December 31, 2017, the Company did not hold interest rate derivatives and therefore, the economic proportion of fixed rate loans and borrowing remained at 98%, consistent with the actual proportion of fixed rate loans and borrowings disclosed above.

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, 2018, a 100 basis point decrease or increase to interest rates would increase or decrease full year net income attributable to common shareholders by $6 million (2017 – less than $1 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)

33. 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	2018	2017
Cash and cash equivalents (note 12)	$ 182	$ 52
Trade and other receivables (note 13) [1]	462	278
Derivative financial instruments assets (note 15) [1]	159	171
Finance lease receivables (note 16)	620	644
Government grant receivable (note 17)	459	493
	$ 1,882	$ 1,638

[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 $186 million (2017 - $142 million) for wholesale counterparties and $435 million (2017 - $307 million) for generation and other counterparties as at December 31, 2018.

The Company is not permitted to sell or re-pledge collateral in the absence of default of the collateral providers. As at December 31, 2018, the Company also held other forms of credit enhancement in the forms of letters of credit of $74 million (2017 - $115 million), parental guarantees of $1,772 million (2017 - $1,467 million) and property registrations $53 million (2017 - $61 million) related to the financial assets noted above. As at December 31, 2018 and 2017, 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 certain development projects and counterparty performance for power purchase arrangements.

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)

33. 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, during January 2019, has filed for bankruptcy and subsequently had its credit rating downgraded to "D", representing default. PG&E is in the midst of political and regulatory pressure as well as uncertainty resulting from claims against them related to wildfires that occurred in 2017 and 2018. 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 industrial and commercial 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, 2018 was:

	Gross trade and other receivables	Allowance for doubtful accounts	Net trade and other receivables
Current [2]	$ 461	$ -	$ 461
Outstanding 30 - 60 days	1	-	1
	$ 462	$ -	$ 462

[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)

33. Risk management, continued:

Credit risk, continued

Trade and other receivables and allowance for doubtful accounts, continued

As at December 31, 2018 and 2017, the Company held no customer deposits for the purpose of mitigating the credit risk associated with accounts receivable from customers.

As at December 31, 2018 and 2017, 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.

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.

As at December 31, 2018, the Company had undrawn bank credit facilities and operating lines of credit and demand facilities, totaling $490 million (2017 - $1,083 million), of which $437 million is committed to 2023 (2017 - $941 million committed to 2022 and $55 million committed to 2020).

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, 2018, 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. As at December 31, 2018, the amounts available on the shelf prospectus are $3,000 million (2017 - $2,017 million).

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, 2018:

	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] (note 23)	$ 419	$ 320	$ 329	$ 18	$ 481	$ 817	$ 2,384
Interest payments on loans and borrowings	106	94	69	60	49	75	453
Trade and other payables [4] (note 22)	229	-	-	-	-	-	229
Finance lease obligation	1	1	1	1	1	13	18
Derivative financial liabilities (net of financial assets):							
Commodity and other derivatives	12	4	6	5	3	70	100
Total	$ 767	$ 419	$ 405	$ 84	$ 534	$ 975	$ 3,184

[3] Repayments of loans and borrowings exclude fair value differentials of $17 million related to debt assumed on previous asset acquisitions and $267 million related to repayments of tax-equity financing through non-cash tax-equity attributes.

[4] Excluding accrued interest on loans and borrowings of $15 million and current portion of finance lease obligation of $1 million.

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

34. 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	2018	2017
Loans and borrowings (note 23)	$ 2,647	$ 2,146
Finance lease obligation (note 16)	18	18
Cash and cash equivalents (note 12)	(182)	(52)
Net debt	2,483	2,112
Non-controlling interests (note 35)	43	48
Share capital (note 27)	3,200	3,262
Deficit and other reserves	(124)	(248)
Total equity	3,119	3,062
	$ 5,602	$ 5,174

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 0.80 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, 2018 and 2017, 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)

35. 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, 2018:

	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	2018	2017
Non-current assets	$ 82	$ 97
Net loss and comprehensive loss attributable to partners	$ (15)	$ (19)

Consolidated statements of cash flows	2018	2017
Net cash flows used in investing activities [1]	$ (14)	$ (16)
Net cash flows from financing activities	14	16
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 balance sheet are comprised of:

Year ended December 31	2018	2017
Non-controlling interest in the Coal Mine, beginning of year	$ 48	$ 58
Net loss attributable to non-controlling interest	(7)	(10)
Non-controlling interest in the Coal Mine, end of year	$ 41	$ 48
Non-controlling interest in Macho Springs, end of year [2]	2	-
Total non-controlling interests, end of year	$ 43	$ 48

[1] Commencing in 2017, the Company is funding 100% of the Coal Mine capital expenditures.

[2] 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. As at December 31, 2018, the non-controlling interest associated with Macho Springs is $2 million.

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

36. Interests in joint arrangements:

Joint operations

The Company holds interests in the following joint operations as at December 31, 2018:

	Place of business	% of ownership interest
Genesee 3 Project (G3) [1]	Canada	50%
Keephills 3 Project (K3) [2]	Canada	50%
Joffre Cogeneration Project (Joffre) [3]	Canada	40%
Shepard Energy Centre (Shepard) [4]	Canada	50%
Genesee 4 and 5 [5]	Canada	50%

[1] G3 is a 516 megawatt (MW) coal-fired generating facility in which Capital Power holds a 50% interest while the other 50% is held by an external party, with Capital Power acting as the manager and operator. Both parties independently dispatch and market their share of the electrical output through Alberta's competitive wholesale market.

[2] K3 is a 516 MW coal-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 facility's electrical output through Alberta's competitive wholesale market.

[3] 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.

[4] Shepard is an 800 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.

[5] 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 37(a).

There are no significant restrictions pertaining to the joint operations described above, other than those described in note 23 pertaining to the charges on the Joffre assets.

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

36. Interests in joint arrangements, continued:

Joint ventures

The Company held interests in the following joint ventures during the year ended December 31, 2018:

	Place of business	Measurement Method
K2 Wind Power Project (K2 Wind) [6]	Canada	Equity method
York Energy Centre L.P. (York Energy) [7]	Canada	Equity method

[6] K2 Wind is a 270 MW wind facility in which Capital Power previously held an equal 33.33% interest with two external parties. The Company's investment in K2 Wind, which consisted of separate legal entities, was determined to be a joint venture. The Company's obligations were limited to their capital contributions to the joint arrangement, and the Company's receipts of the economic benefits of the joint arrangement were limited to annual distributions. As a result, there was no indication that the Company had rights to the assets or obligations for the liabilities of the joint arrangement and the investment was classified as a joint venture. On December 31, 2018, Capital Power disposed of its interest in K2 Wind as described in note 7.

[7] York Energy is a 400 MW natural gas-fired power generating facility 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. 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.

The summarized financial information of K2 Wind is as follows:

Statements of Financial Position	2018	2017
Cash and cash equivalents	$ -	$ 16
Other current assets	-	23
Non-current assets [8]	-	794
Financial current liabilities	-	(47)
Financial non-current liabilities	-	(769)
Other non-current liabilities	-	(15)
Net assets	$ -	$ 2

[8] K2 Wind had restricted cash of $8 million included in non-current assets above as at December 31, 2017 which represented security for a standby line of credit with a third party.

Statements of Income and Comprehensive Income	2018 [9]	2017
Revenues	$ 105	$ 143
Other raw materials and operating charges	(10)	(12)
Other administrative expense	(5)	(6)
Depreciation and amortization	(30)	(35)
Finance expense	(31)	(38)
Net income	29	52
Other comprehensive income:		
Unrealized gains on derivative instruments	13	11
Reclassification of losses on derivative instruments to net income for the year	8	14
Total comprehensive income	$ 50	$ 77

[9] 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.

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

36. Interests in joint arrangements, continued:

Joint ventures, continued

A reconciliation of the Company's recorded equity investment in K2 Wind is as follows:

	2018	2017
Equity-accounted investment in K2 Wind, as at January 1	$ 33	$ 18
Proportionate share of comprehensive income (33.33%)	17	26
Distributions received – operating	(16)	(20)
Adjustments for differences in accounting policies	7	9
Disposal of investment in K2 Wind	(41)	-
Equity-accounted investment in K2 Wind, as at December 31	$ -	$ 33

The summarized financial information of York Energy is as follows:

Statements of Financial Position	2018	2017
Cash and cash equivalents	$ 3	$ 4
Other current assets	13	13
Non-current assets [10]	226	232
Financial current liabilities	(18)	(18)
Financial non-current liabilities	(236)	(246)
Other non-current liabilities	(2)	(2)
Net assets	$ (14)	$ (17)

[10] York Energy has restricted cash of $7 million (2017 - $6 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 [11]	2018	2017
Revenues	$ 60	$ 42
Energy purchases and fuel	(8)	(6)
Other raw materials and operating charges	(4)	(2)
Other administrative expense	(1)	(1)
Depreciation and amortization	(9)	(6)
Finance expense	(13)	(2)
Net income and comprehensive income	$ 25	$ 25

[11] Statements of Income and Comprehensive Income include activity following the acquisition date of April 13, 2017.

A reconciliation of the Company's recorded equity investment in York Energy is as follows:

	2018	2017
Equity-accounted investment in York Energy, as at January 1	$ 151	$ -
Acquisition of equity-accounted investment in York Energy	-	153
Proportionate share of comprehensive income (50%)	13	13
Distributions received – operating	(11)	(7)
Amortization of the Company's fair value of net assets acquired	(11)	(8)
Equity-accounted investment in York Energy, as at December 31	$ 142	$ 151

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

36. Interests in joint arrangements, continued:

Joint ventures, continued

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 $8 million in 2019, $29 million from 2020 to 2023 and $21 million after five years. The Company's share of approximate future payments for the operating and maintenance contract is $1 million in 2019 and $11 million from 2020 to 2023.

37. 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 proposed 298.8 MW wind facility in Southeast Alberta to be developed in two phases. During the fourth quarter of 2017, the first 201.6MW phase of the Whitla Wind project (Whitla Wind) was awarded a 20-year contract by the Alberta Electric System Operator (AESO) in the first round of its Renewable Electricity Program. The Company expects the construction cost for the first phase of Whitla Wind to be between $315 million and $325 million with an expected commercial operation date in the fourth quarter of 2019.

(c) During the second quarter of 2018, the Company announced the construction of Cardinal Point Wind would proceed once all applicable regulatory approvals are received. Cardinal Point Wind is a 150 MW facility to be constructed in the McDonough and Warren Counties, Illinois, and is anticipated to cost between $289 million and $301 million (US$236 million to US$246 million). Commercial operation of the facility is expected in March of 2020.

(d) The Company is party to a number of long-term energy purchase and transportation contracts, operating and maintenance contracts, contracts to purchase environmental credits and operating leases for premises in the normal course of operations. 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. The energy purchase and transportation contract amounts disclosed below are based on gross settlement amounts. The contracts to purchase environmental credits disclosed below are presented net of environmental credits sales in the respective periods.

Approximate future payments under each group of contracts are as follows:

	Energy purchase and transportation contracts	Operating and maintenance contracts	Environmental credits	Operating leases
Within one year	$ 48	$ 37	$ 28	$ 11
Between one and five years	103	167	14	37
After five years	490	205	9	94
	$ 641	$ 409	$ 51	$ 142

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

37. Commitments and contingencies, continued:

(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 to 2017.

The Company is participating in appeal processes rendering the final outcome of the LLR Proceeding still unknown. However, based on the current decision, Capital Power would incur additional charges related to transmission amounts of historical periods and as such recorded a current provision of $9 million during the fourth quarter of 2017, pertaining to the estimated net liability for its currently held Alberta assets, within energy purchases and fuel.

(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, 2018, contingent consideration of $12 million (US$9 million) (2017 - $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.

(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.

38. Guarantees:

The Company, through its subsidiary CPLP, has issued letters of credit of $271 million (2017 - $169 million) to meet the credit requirements of energy market participants, to meet conditions of certain service agreements, and to satisfy legislated reclamation requirements.

39. 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 and certain asset balances within each geographic area are:

	Year ended December 31, 2018				Year ended December 31, 2017			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$1,045	$ 204	$ -	$1,249	$ 826	$ 220	$ -	$ 1,046
Revenues - inter-area	21	30	(51)	-	45	61	(106)	-
Other income	65	80	-	145	63	37	-	100
Total revenues and other income	$1,131	$ 314	$ (51)	$1,394	$ 934	$ 318	$ (106)	$ 1,146

	As at December 31, 2018			As at December 31, 2017		
	Canada	U.S.	Total	Canada	U.S.	Total
Property, plant and equipment	$ 3,394	$ 1,409	$ 4,803	$ 3,465	$ 913	$ 4,378
Intangible assets	249	224	473	309	92	401
Goodwill	35	-	35	35	-	35
Other assets	65	1	66	67	1	68
	$ 3,743	$ 1,634	$ 5,377	$ 3,876	$1,006	$ 4,882

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

39. Segment information, continued:

The Company's revenues from contracts with customers are disaggregated by major type of revenues and operational groupings of revenues:

	Year ended December 31, 2018						
	Alberta Commercial	Alberta Contracted	Ontario and British Columbia Contracted	U.S. Contracted	Total from contracts with customers	Other sources	Total
Energy revenues	$ 525	$ 7	$ 3	$ 88	$ 623	$ 576	$ 1,199
Emission credit revenues	23	-	-	4	27	23	50
Total revenues [1]	$ 548	$ 7	$ 3	$ 92	$ 650	$ 599	$1,249

[1] Included within trade and other receivables, as at December 31, 2018, were amounts related to contracts with customers of $172 million.

40. Subsequent events:

$300 million medium-term note issuance

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. The net proceeds of the offering will be used to repay indebtedness under the Company's credit facilities or for general corporate purposes.

Approval of normal course issuer bid

Subsequent to the end of 2018, the Toronto Stock Exchange approved Capital Power's normal course issuer bid to purchase and cancel up to 9.0 million of its outstanding common shares during the one-year period from February 21, 2019 to February 20, 2020.

41. Comparative figures:

Certain comparative figures have been reclassified to conform to the current year's presentation.