ATLANTIC POWER CORP
Form 10-Q
May 02, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10 Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2019

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

COMMISSION FILE NUMBER 001 34691

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada	55 0886410
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3 Allied Drive, Suite 155	
Dedham, MA	02026
(Address of principal executive offices)	(Zip code)

(617) 977 2400

(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b 2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non accelerated filer Smaller reporting company
Emerging growth company

If an emerging company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b 2 of the Exchange Act). Yes No

The number of shares outstanding of the registrant's Common Stock as of May 1, 2019 was 109,694,985

Securities registered pursuant to Section 12(b) of the Act:

The number of shares outstanding of the registrant's Common Stock as of May 1, 2019 was 109,694,985

Securities registered pursuant to Section 12(b) of the Act:If an emerging company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b 2 of the Exchange Act). Yes No

Securities registered pursuant to Section 12(B) of the Act:

Title of Each Class	Trading symbol	Name of Exchange on which registered
Common Shares, no par value, and the associated Rights to Purchase Common Shares	AT	The New York Stock Exchange

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ATLANTIC POWER CORPORATION

FORM 10 Q

THREE MONTHS ENDED MARCH 31, 2019

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GENERAL

In this Quarterly Report on Form 10 Q, references to “Cdn$” and “Canadian dollars” are to the lawful currency of Canada and references to “$”, “US$” and “U.S. dollars” are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

Unless otherwise stated, or the context otherwise requires, references in this Quarterly Report on Form 10 Q to “we,” “us,” “our,” “Atlantic Power” and the “Company” refer to Atlantic Power Corporation, those entities owned or controlled by Atlantic Power Corporation and predecessors of Atlantic Power Corporation.

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ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

Assets	March 31, 2019 (unaudited)	December 31, 2018
Current assets:		
Cash and cash equivalents	$ 74.8	$ 68.3
Restricted cash	0.5	2.1
Accounts receivable	29.1	35.7
Current portion of derivative instruments asset (Notes 7 and 8)	2.7	4.2
Inventory	13.1	15.8
Prepayments	5.4	4.0
Income taxes receivable	—	0.3
Other current assets	6.1	5.9
Total current assets	131.7	136.3
Property, plant, and equipment, net	543.5	549.5
Equity investments in unconsolidated affiliates (Note 4)	147.2	140.8
Power purchase agreements and intangible assets, net	163.3	170.1
Goodwill	21.3	21.3
Derivative instruments asset (Notes 7 and 8)	—	0.3
Right of use lease asset (Note 15)	6.1	—
Other assets	6.2	6.2
Total assets	$ 1,019.3	$ 1,024.5
Liabilities		
Current liabilities:		
Accounts payable	$ 4.0	$ 2.5
Income taxes payable	0.2	—
Accrued interest	3.7	2.3
Other accrued liabilities	13.1	20.2
Current portion of long-term debt (Note 5)	78.1	68.1
Current portion of derivative instruments liability (Notes 7 and 8)	11.0	4.5
Convertible debentures (Note 6)	18.5	18.1
Short-term lease liability (Note 15)	1.5	—
Other current liabilities	0.4	0.2
Total current liabilities	130.5	115.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 5)	519.6	540.7
Convertible debentures, net of discount and unamortized deferred financing costs (Note 6)	77.8	75.7
Derivative instruments liability (Notes 7 and 8)	14.8	15.4

Deferred income taxes	8.1	9.0
Power purchase agreements and intangible liabilities, net	20.9	21.2
Asset retirement obligations, net	49.7	49.2
Long-term lease liability (Note 15)	5.1	—
Other long-term liabilities	5.0	5.0
Total liabilities	831.5	832.1
Equity		
Common shares, no par value, unlimited authorized shares; 109,688,979 and 108,341,738 issued and outstanding at March 31, 2019 and December 31, 2018	1,261.4	1,260.9
Accumulated other comprehensive loss (Note 3)	(144.1)	(146.2)
Retained deficit	(1,112.7)	(1,121.6)
Total Atlantic Power Corporation shareholders' equity	4.6	(6.9)
Preferred shares issued by a subsidiary company (Note 12)	183.2	199.3
Total equity	187.8	192.4
Total liabilities and equity	$ 1,019.3	$ 1,024.5

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

	Three Months Ended March 31, 2019	2018
Project revenue:		
Energy sales (Note 2)	$ 37.0	$ 38.4
Energy capacity revenue (Note 2)	30.2	20.1
Other (Note 2)	5.8	21.5
	73.0	80.0
Project expenses:		
Fuel	20.0	22.2
Operations and maintenance	16.5	21.2
Depreciation and amortization	16.2	23.8
	52.7	67.2
Project other income (loss):		
Change in fair value of derivative instruments (Notes 7 and 8)	(2.4)	3.8
Equity in earnings of unconsolidated affiliates (Note 4)	12.9	12.3
Interest, net	(0.3)	(0.6)
Other income, net	0.1	—
	10.3	15.5
Project income	30.6	28.3
Administrative and other expenses:		
Administration	6.8	6.0
Interest expense, net	11.1	15.1
Foreign exchange loss (gain)	5.0	(8.2)
Other expense (income), net (Note 8)	4.7	(2.0)
	27.6	10.9
Income from operations before income taxes	3.0	17.4
Income tax expense (Note 9)	0.6	3.2
Net income	2.4	14.2
Net loss attributable to preferred shares of a subsidiary company (Note 12)	(6.5)	(1.7)
Net income attributable to Atlantic Power Corporation	$ 8.9	$ 15.9
Net earnings per share attributable to Atlantic Power Corporation shareholders: (Note 11)		
Basic	$ 0.08	$ 0.14
Diluted	0.07	0.12

Weighted average number of common shares outstanding: (Note 11)		
Basic	108.9	114.8
Diluted	138.6	140.6

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of U.S. dollars)

(Unaudited)

	Three Months Ended March 31,	
	2019	2018
Net income	$ 2.4	$ 14.2
Other comprehensive income, net of tax:		
Unrealized (loss) gain on hedging activities	$ (0.2)	$ 0.2
Net amount reclassified to earnings	0.1	0.1
Net realized and unrealized (loss) gain on derivatives	(0.1)	0.3
Foreign currency translation adjustments	2.2	(4.6)
Other comprehensive income (loss), net of tax	2.1	(4.3)
Comprehensive income	4.5	9.9
Less: Comprehensive loss attributable to preferred shares of a subsidiary company	(6.5)	(1.7)
Comprehensive income attributable to Atlantic Power Corporation	$ 11.0	$ 11.6

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

(Unaudited)

	Three months ended March 31, 2019	2018
Cash provided by operating activities:		
Net income	$ 2.4	$ 14.2
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	16.2	23.8
Share-based compensation	0.6	0.5
Equity in earnings from unconsolidated affiliates	(12.9)	(12.3)
Distributions from unconsolidated affiliates	5.8	6.6
Unrealized foreign exchange loss (gain)	5.3	(8.0)
Change in fair value of derivative instruments	7.1	(5.9)
Amortization of debt discount, deferred financing costs and right of use lease asset	2.3	3.4
Change in deferred income taxes	(0.7)	2.2
Change in other operating balances		
Accounts receivable	5.1	26.1
Inventory	2.7	1.6
Prepayments and other assets	(1.4)	0.8
Accounts payable	1.9	3.2
Accruals and other liabilities	(5.2)	(5.9)
Cash provided by operating activities	29.2	50.3
Cash provided by (used in) investing activities:		
Proceeds from asset sales	1.5	—
Purchase of property, plant and equipment	(0.3)	(1.1)
Cash provided by (used in) investing activities	1.2	(1.1)
Cash used in financing activities:		
Proceeds from convertible debenture issuance	—	92.2
Repayment of convertible debentures	—	(88.1)
Common share repurchases	(0.1)	(6.4)
Preferred share repurchases	(7.7)	(4.0)
Repayment of corporate and project-level debt	(15.8)	(32.4)
Deferred financing costs	—	(4.8)
Dividends paid to preferred shareholders	(1.9)	(2.2)
Cash used in financing activities:	(25.5)	(45.7)

Net increase in cash, restricted cash and cash equivalents	4.9	3.5
Cash, restricted cash and cash equivalents at beginning of period	70.4	84.8
Cash, restricted cash and cash equivalents at end of period	$ 75.3	$ 88.3
Supplemental cash flow information		
Interest paid	$ 8.2	$ 8.6
Income taxes paid, net	$ 0.8	$ 1.0
Accruals for construction in progress	$ —	$ 0.3

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

1. Nature of business

General

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long term power purchase agreements (“PPAs”), which seek to minimize exposure to changes in commodity prices. As of March 31, 2019, our portfolio consisted of seventeen operating projects with an aggregate electric generating capacity of approximately 1,598 megawatts (“MW”) on a gross ownership basis and approximately 1,252 MW on a net ownership basis. Fourteen of the projects are majority owned by the Company.

Atlantic Power is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange (“TSX”) under the symbol “ATP” and on the New York Stock Exchange (“NYSE”) under the symbol “AT.” Our registered office is located at 215-10451 Shellbridge Way, Richmond, British Columbia V6X 2W8 Canada and our headquarters is located at 3 Allied Drive, Suite 155, Dedham, Massachusetts 02026, USA. Our telephone number in Dedham is (617) 977 2400 and the address of our website is www.atlanticpower.com. Information contained on Atlantic Power’s website or that can be accessed through its website is not incorporated into and does not constitute a part of this Quarterly Report on Form 10 Q. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website. We make available on our website, free of charge, our Annual Report on Form 10 K, Quarterly Reports on Form 10 Q, Current Reports on Form 8 K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (“SEC”). Additionally, we make available on our website our Canadian securities filings, which are not incorporated by reference into our Exchange Act filings.

Basis of presentation

The interim condensed consolidated financial statements included in this Quarterly Report on Form 10 Q have been prepared in accordance with the SEC regulations for interim financial information and with the instructions to Form 10 Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10 K for the year ended December 31, 2018. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim condensed consolidated financial statements present fairly our consolidated financial position as of March 31, 2019, the results of operations and comprehensive income for the three months ended March 31, 2019 and 2018, and our cash flows for the three months ended March 31, 2019 and 2018 in accordance with U.S. generally accepted accounting policies. In the opinion of management, all adjustments (consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair value of assets acquired and liabilities assumed in purchase accounting, the useful lives and recoverability of property, plant and

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations and equity-based compensation. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" in our Annual Report on Form 10-K for the year ended December 31, 2018. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Recently adopted and issued accounting standards

Accounting Standards Adopted

In February 2016, the FASB issued authoritative guidance intended to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a right-of-use asset and a lease liability, measured on a discounted basis, at the commencement date for all leases with terms greater than twelve months. Additionally, this guidance will require disclosures to help investors and other financial statement users to better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements. Any leases that expire before the initial application date will not require any accounting adjustment. This guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We adopted this guidance and related updates issued in July 2018 and December 2018 on January 1, 2019 and elected certain practical expedients permitted, including the expedient that permits us to retain our existing lease assessment and classification. In July 2018, the FASB issued further authoritative guidance to provide an additional transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustments to the opening balance of retained earnings in the period of adoption. We elected this transition method.

As the result of our adoption of the guidance, we recorded $6.4 million and $7.2 million of right of use assets and lease liabilities, respectively, in the consolidated balance sheets on January 1, 2019. We have no transitional adjustments to our opening retained earnings or our consolidated statements of operations. See Note 15, Leases for further information.

In August 2017, the FASB issued authoritative guidance to align an entity’s risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The guidance expands and refines hedge accounting for both nonfinancial and financial risk components and aligns the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. We adopted this guidance on January 1, 2019 and it did not have an impact on the consolidated financial statements.

In February 2018, the FASB issued authoritative guidance to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. We adopted this guidance on January 1, 2019 and it did not have an impact on the consolidated financial statements.

Accounting Standards Issued

In August 2018, the FASB issued authoritative guidance to modify the disclosure requirements on fair value measurement disclosures. The guidance requires removals of certain disclosures, such as the amount of and reasons for

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

transfers between level 1 and level 2 of fair value hierarchy and the policy for timing of transfers between levels. The guidance further requires modifications and additions surrounding the disclosures of level 3 fair value measurements and related unrealized gains and losses. The guidance is effective for fiscal years beginning after December 15, 2019. We do not expect this to have a material impact to the consolidated financial statements upon adoption.

In August 2018, the FASB issued authoritative guidance to remove disclosures that no longer are considered cost-beneficial, clarify the specific requirements of disclosures, and add disclosure requirements identified as relevant. The scope of the guidance is broad and includes reporting comprehensive income, debt modifications and extinguishments and other sub topics. The guidance is effective for fiscal years beginning after December 15, 2019. We are currently evaluating the impact that adoption will have on our disclosures.

2. Revenue from contracts

Disaggregation of revenue

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. Each segment contains various power generation projects and performance obligations as described above. For more detailed information about reportable segments, see Note 13, Segment and geographical information. Revenue, receivables and contract liabilities by segment consists of following:

	Three Months Ended March 31, 2019				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 26.8	$ 2.9	$ 7.3	$ —	$ 37.0
Energy capacity revenue	12.4	5.0	12.8	—	30.2
Steam energy and capacity revenue	0.6	—	—	—	0.6
Ancillary and transmission services	4.3	—	0.8	—	5.1
Asset management and operation	—	—	—	0.2	0.2
Miscellaneous revenue	—	(0.1)	—	—	(0.1)
	44.1	7.8	20.9	0.2	73.0

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

	Three Months Ended March 31, 2018				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 25.3	$ 5.1	$ 8.0	$ —	$ 38.4
Energy capacity revenue	11.3	5.9	2.9	—	20.1
Steam energy and capacity revenue	3.6	2.8	—	—	6.4
Waste heat revenue	—	—	0.1	—	0.1
Enhanced dispatch contracts	—	—	9.1	—	9.1
Ancillary and transmission services	1.4	—	4.4	—	5.8
Asset management and operation	—	—	—	0.2	0.2
Miscellaneous revenue	—	(0.2)	0.1	—	(0.1)
	41.6	13.6	24.6	0.2	80.0

Contract balances

The following table provides information about receivables, contract assets and contract liabilities from contracts with customers.

	March 31, 2019	December 31, 2018
Accounts receivables	$ 29.1	$ 35.7
Contract liabilities	0.4	0.1

Contract liabilities as of March 31, 2019 include a $0.1 million steam sale credit at the San Diego plants and a $0.3 million water license fee at Mamquam, which is a pass-through cost. Contract liabilities as of December 31, 2018 include a $0.1 million steam sale credit at San Diego plants, which remains on the account for March 31, 2019. We had no contract assets at March 31, 2019 and December 31, 2018.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

3. Changes in accumulated other comprehensive loss by component

The changes in accumulated other comprehensive loss by component were as follows:

	Three Months Ended March 31,	
	2019	2018
Foreign currency translation		
Balance at beginning of period	$ (146.4)	$ (134.3)
Other comprehensive income (loss):		
Foreign currency translation adjustments(1)	2.2	(4.6)
Balance at end of period	$ (144.2)	$ (138.9)
Pension		
Balance at beginning and end of period	$ (1.4)	$ (1.6)
Cash flow hedges		
Balance at beginning of period	$ 1.6	$ 1.1
Other comprehensive income (loss):		
Net change from periodic revaluations	(0.2)	0.3
Tax expense	—	(0.1)
Total Other comprehensive (loss) income before reclassifications, net of tax	(0.2)	0.2
Net amount reclassified to earnings:		
Interest rate swaps(2)	0.1	0.1
Tax expense	—	—
Total amount reclassified from accumulated other comprehensive loss, net of tax	0.1	0.1
Total other comprehensive (loss) income	(0.1)	0.3
Balance at end of period	$ 1.5	$ 1.4

(1)

In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in interest expense, net on the accompanying consolidated statements of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

(3)

4. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three months ended March 31, 2019 and 2018, respectively, for our proportional ownership interest in equity method investments:

	Three Months Ended March 31,	
Operating results	2019	2018
Revenue		
Frederickson	$ 5.8	$ 5.1
Orlando Cogen, LP	15.5	14.4
Koma Kulshan Associates (1)	—	0.2
Chambers Cogen, LP	11.5	13.2
	32.8	32.9
Project expenses		
Frederickson	3.4	3.2
Orlando Cogen, LP	7.5	7.1
Koma Kulshan Associates (1)	—	0.3
Chambers Cogen, LP	8.6	9.6
	19.5	20.2
Project other expense		
Frederickson	—	—
Orlando Cogen, LP	—	—
Koma Kulshan Associates (1)	—	—
Chambers Cogen, LP	(0.4)	(0.4)
	(0.4)	(0.4)
Project income (loss)		

Frederickson	2.4	1.9
Orlando Cogen, LP	8.0	7.3
Koma Kulshan Associates (1)	—	(0.1)
Chambers Cogen, LP	2.5	3.2
Equity in earnings of unconsolidated affiliates	$ 12.9	$ 12.3
Distributions from equity method investments	(5.8)	(6.6)
Surplus of earnings of equity method investments, net of distributions	$ 7.1	$ 5.7

(1) On July 27, 2018, we purchased the remaining 50% of Koma and consolidated the project.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

5. Long term debt

Long term debt consists of the following:

	March 31, 2019	December 31, 2018	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2023(1)	$ 435.0	$ 450.0	LIBOR(2) plus 2.75 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	157.1	154.0	5.95 %
Non-Recourse Debt:			
Cadillac term loan, due 2025 (3)	20.3	21.0	LIBOR plus 1.49 %
Less: unamortized discount	(8.2)	(9.0)	
Less: unamortized deferred financing costs	(6.5)	(7.2)	
Less: current maturities	(78.1)	(68.1)	
Total long-term debt	$ 519.6	$ 540.7	

Current maturities consist of the following:

	March 31, 2019	December 31, 2018	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2023(1)	$ 75.0	$ 65.0	LIBOR(2) plus 2.75 %
Cadillac term loan, due 2025 (3)	3.1	3.1	LIBOR plus 1.49 %
Total current maturities	$ 78.1	$ 68.1	

(1)

On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the term loan credit agreement. The portion of the senior secured term loan facility classified as current is based on principal payments required to reduce the aggregate principal amount of senior secured term loan outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

(2) London Interbank Offered Rate (“LIBOR”) cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $395.7 million of the $435 million outstanding aggregate borrowings under our senior secured term loan facility at March 31, 2019. See Note 8, Accounting for derivative instruments and hedging activities for further details.

(3) We have entered into interest rate swap agreements to economically fix our exposure to changes in interest rates for this non-recourse debt. See Note 8, Accounting for derivative instruments and hedging activities, for further details.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

6. Convertible debentures

Convertible debentures consist of the following:

	March 31, 2019	December 31, 2018
6.00% Debentures due January 2025 (Series E) (Cdn $115.0 million)	$ 86.1	$ 84.3
6.00% Debentures due December 2019 (Series D) (Cdn $24.7 million)	18.5	18.1
Less: Unamortized deferred financing costs	(4.4)	(4.6)
Less: Unamortized discount	(3.9)	(4.0)
Total current and long-term convertible debentures	$ 96.3	$ 93.8

At March 31, 2019, we had $18.5 million (Cdn$24.7 million) principal amount outstanding 6.00% Debentures due December 2019 (the “Series D Debentures”). We pay interest semi annually on the last day of June and December of each year for the Series D Debentures. They were convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$14.50 per common share.

On April 10, 2019, we redeemed, in full, the aggregate principal amount of Cdn$24.7 million of the outstanding Series D Debentures and paid accrued interest of Cdn$0.4 million.

Series E Debentures

On January 29, 2018, we closed the Series E Debentures Offering of Cdn$100 million aggregate principal amount of Series E Debentures. We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debentures offering to cover over-allotments. The underwriters exercised that option, for the full Cdn$15 million aggregate principal amount, on February 2, 2018.

The Series E Debentures have a maturity date of January 31, 2025. The Series E Debentures bear interest at a rate of 6.00% per year, and are convertible into our common shares at an initial conversion rate of approximately 238.0952 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$4.20 per common share. The Series E Debentures may not be redeemed by the Company prior to January 31, 2021 (except in certain limited circumstances following a change of control). On and after January 31, 2021 and prior to January 31, 2023, the Series E Debentures may be redeemed by us, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the daily volume-weighted average trading price of our common shares on the Toronto Stock Exchange, averaged for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided, is not less than 125% of the conversion price at the time notice of redemption is given. On and after January 31, 2023 and prior to the maturity date, the Series E Debentures may be redeemed in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption. The Series E Debentures are our direct, subordinated, unsecured obligations and rank equally with the other series of debentures and with all other future subordinated unsecured indebtedness and rank subordinate to all of our existing and future senior indebtedness.

On the initial closing date, we received net proceeds from the Series E Debentures offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On March 2, 2018, we redeemed all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E

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Debentures Offering. On March 3, 2018, we redeemed Cdn$56.2 million principal amount of the Series D Debentures with the remaining proceeds from the Series E Debentures Offering.

Series E Conversion Option

We assessed the conversion option of the Series E Debentures and determined it should be separated from the host instrument and accounted for as an embedded derivative liability as the conversion option is in a currency different from our functional currency. Changes in the fair value of the conversion option derivative are recorded in the consolidated statements of operation. The conversion option derivative was initially measured at fair value ($4.7 million), with the host contract carried at a value equal to the difference between the carrying value of the Series E Debenture and the fair value of the derivative. Accordingly, no gain or loss was recorded on the initial measurement of the derivative. The fair value of the conversion option derivative liability was $6.0 million and $1.2 million at March 31, 2019 and December 31, 2018, respectively. The portion of the proceeds allocated to the separated derivative also created a discount of $4.7 million, which will be amortized to interest expense over the maturity period of the Series E Debentures. For additional information, see Note 8, Accounting for derivative instruments and hedging activities.

7. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as March 31, 2019 and December 31, 2018. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

March 31, 2019

	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 74.8	$ —	$ —	$ 74.8
Restricted cash	0.5	—	—	0.5
Derivative instruments asset	—	2.7	—	2.7
Total	$ 75.3	$ 2.7	$ —	$ 78.0
Liabilities:				
Derivative instruments liability	$ —	$ 19.8	$ 6.0	$ 25.8
Total	$ —	$ 19.8	$ 6.0	$ 25.8

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 68.3	$ —	$ —	$ 68.3
Restricted cash	2.1	—	—	2.1
Derivative instruments asset	—	4.5	—	4.5
Total	$ 70.4	$ 4.5	$ —	$ 74.9
Liabilities:				
Derivative instruments liability	$ —	$ 18.7	$ 1.2	$ 19.9
Total	$ —	$ 18.7	$ 1.2	$ 19.9

The fair values of our interest rate swaps, foreign exchange forward contracts, natural gas swaps and gas purchase agreements are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and

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derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk-free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of March 31, 2019, the credit valuation adjustments resulted in a $0.9 million net increase in fair value, which consists of a $0.1 million pre tax gain in other comprehensive income and a $0.8 million gain in change in fair value of derivative instruments. As of December 31, 2018, the credit valuation adjustments resulted in a $1.0 million net increase in fair value, which consists of a $0.1 million pre tax gain in other comprehensive income and a $0.9 million gain in change in fair value of derivative instruments.

The conversion option derivative for the Series E Debentures is classified within Level 3 of the fair value hierarchy. The significant unobservable inputs used in developing fair value include the volatility of our common shares and the fair value of the host contract, which is derived from recent similar convertible debenture offerings from peer companies. A discounted cash flow valuation technique is utilized to calculate to fair value of the conversion option derivative.

The following table reconciles, for the three months ended March 31, 2019 and 2018, the beginning and ending balances for the conversion option derivative that is recognized at fair value in the consolidated financial statements, using significant unobservable inputs:

	Fair value Measurement Using Significant Unobservable Inputs (Level 3)

	Three months ended March 31, 2019	
Beginning balance of liability at January 1, 2019	$	1.2
Total unrealized loss		4.7
Currency transaction loss		0.1
Ending balance of liability at March 31, 2019	$	6.0

	Fair value Measurement Using Significant Unobservable Inputs (Level 3) Three months ended March 31, 2018	
Balance of liability at inception (January 2018)	$	4.7
Total unrealized gain		(2.1)
Ending balance of liability at March 31, 2018	$	2.6

For cash and cash equivalents, accounts and other receivables, accounts payable and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

8. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value in each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective

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portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase and sale agreements

We have a gas purchase agreement at our Nipigon project that expires on December 31, 2022 under which we purchase a minimum of 6,500 Gigajoules ("Gj") of natural gas per day at a price of Cdn$4.57 per Gj. This agreement does not qualify for the normal purchase normal sales ("NPNS") exemption and is accounted for as a derivative financial instrument because we could not conclude that it is probable that this contract will not settle net and will result in physical delivery. This derivative financial instrument is recorded in the consolidated balance sheets at fair value and the changes in its fair market value is recorded in the consolidated statements of operations. We also have a corresponding gas sales agreement at Nipigon, whereby 6,500 Gj of natural gas per day is sold at the spot market price. This contract is not accounted for as a derivative.

On April 8, 2019, we also entered into natural gas purchase agreements at our Morris project for approximately 350,000 MMBtu to effectively mitigate seasonal fluctuations of future natural gas prices from May 2019 through June 2019. This contract is accounted for as a derivative financial instrument and will be recorded in the consolidated balance sheet at fair value. Changes in the fair market value of this contract will be recorded in the consolidated statement of operations.

Natural gas swaps

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas swaps to effectively fix the price of 15.3 million Mmbtu of future natural gas purchases at our Orlando project, which is approximately 100% of our share of the expected natural gas purchases in 2019 through 2022. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at March 31, 2019. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

Atlantic Power Limited Partnership Holdings ("APLP Holdings") has entered into several interest rate swap agreements to mitigate its exposure to changes in interest at the Adjusted Eurodollar Rate. At March 31, 2019, these agreements totaled $395.7 million notional amount of the remaining $435.0 million aggregate principal amount of borrowings under the senior secured term loan facility ("Term Loan Facility"). These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the $700.0 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.75% all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 1.25%, resulting in an all-in rate of approximately 4.00% for $395.7 million of the Term Loan Facility.
In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning September 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million

notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.1% through February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive income (loss).

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our Medium Term Notes due June 23, 2036 ("MTNs"). Principal and interest payments for our senior secured term loans are made in U.S. dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements. Foreign currency forward contracts are not designated as hedges, and changes in their market value are recorded in foreign exchange on the consolidated statements of operations. As of March 31, 2019, we have no foreign currency forward contracts.

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for NPNS exemption at March 31, 2019 and December 31, 2018:

	Units	March 31, 2019	December 31, 2018
Natural gas swaps	Natural Gas (Mmbtu)	15.3	16.3
Gas purchase agreements	Natural Gas (Gigajoules)	8.9	9.0
Interest rate swaps	Interest (US$)	600.5	616.6

Fair value of derivative instruments

We disclose derivative instrument assets and liabilities on a trade by trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

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	March 31, 2019	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.4
Interest rate swaps long-term	—	1.1
Total derivative instruments designated as cash flow hedges	—	1.5
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	2.7	—
Interest rate swaps long-term	—	0.4
Natural gas swaps long-term	—	1.4
Gas purchase agreements current	—	4.6
Gas purchase agreements long-term	—	11.9
Convertible debenture conversion option	—	6.0
Total derivative instruments not designated as cash flow hedges	2.7	24.3
Total derivative instruments	$ 2.7	$ 25.8

	December 31, 2018	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.4
Interest rate swaps long-term	—	1.0
Total derivative instruments designated as cash flow hedges	—	1.4
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	4.2	—
Interest rate swaps long-term	0.3	—
Natural gas swaps current	—	0.1
Natural gas swaps long-term	—	1.4

Gas purchase agreements current	—	2.8
Gas purchase agreements long-term	—	13.0
Convertible debenture conversion option	—	1.2
Total derivative instruments not designated as cash flow hedges	4.5	18.5
Total derivative instruments	$ 4.5	$ 19.9

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Accumulated other comprehensive income

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

Three Months Ended March 31, 2019	Interest Rate Swaps
Accumulated OCI balance at January 1, 2019	$ 1.6
Change in fair value of cash flow hedges	(0.2)
Realized from OCI during the period	0.1
Accumulated OCI balance at March 31, 2019	$ 1.5

Three Months Ended March 31, 2018	Interest Rate Swaps
Accumulated OCI balance at January 1, 2018	$ 1.1
Change in fair value of cash flow hedges	0.2
Realized from OCI during the period	0.1
Accumulated OCI balance at March 31, 2018	$ 1.4

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

	Classification of loss (gain) recognized in income	Three Months Ended March 31, 2019	2018
Gas purchase agreements	Fuel	$ 2.0	$ 0.8
Natural gas swaps	Fuel	(0.3)	0.4
Interest rate swaps	Interest, net	(1.3)	(0.6)

The following table summarizes the unrealized (loss) gain resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Classification of (loss) gain recognized in income	Three Months Ended March 31, 2019	2018
Natural gas swaps	Change in fair value of derivatives	$ 0.2	$ (0.2)
Gas purchase agreements	Change in fair value of derivatives	(0.4)	(1.3)
Interest rate swaps	Change in fair value of derivatives	(2.2)	(2.3)
		$ (2.4)	$ (3.8)
Convertible debenture conversion option	Other expense, net	4.7	(2.1)
Foreign currency forwards	Foreign exchange loss	$ —	$ (0.5)

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9. Income taxes

	Three Months Ended March 31,	
	2019	2018
Current income tax expense	$ 1.3	$ 1.0
Deferred income tax (benefit) expense	(0.7)	2.2
Total income tax expense, net	$ 0.6	$ 3.2

For the three months ended March 31, 2019 and 2018

Income tax expense for the three months ended March 31, 2019 was $0.6 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $0.8 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 which have been reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, base erosion and anti-abuse tax. Based on estimates as of the date of this filing, we will not be subject to the base erosion and anti-abuse tax. Our interest expense deduction may be limited, but will not have a material impact on cash taxes. The primary item impacting the tax rate for the three months ended March 31, 2019 was a net decrease to our valuation allowances of $1.6 million, consisting of $1.7 million increase in Canada and $3.3 million decreases in the United States due to income. These items were partially offset by $0.7 million relating to foreign exchange, $0.4 million relating to withholding state taxes and $0.3 million of other permanent differences.

Income tax expense for the three months ended March 31, 2018 was $3.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $4.5 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the Internal Revenue Code.

Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 which have been reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, and base erosion and anti-abuse tax. Based on estimates as of the date of this filing, the interest expense limitation and base erosion and anti-abuse tax will not have a material impact to cash taxes. The primary items impacting the tax rate for the three months ended March 31, 2018 was a net increase to our valuation allowances of $0.8 million, consisting of a $0.8 million increase in Canada related to losses and no change in the United States. In addition, the rate was further impacted by $0.1 million of other permanent differences. These items were offset by $1.3 million relating to capital loss on intercompany notes and $0.9 million relating to changes in tax rates.

As of March 31, 2019, we have recorded a valuation allowance of $138.1 million. The amount is comprised primarily of provisions against Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected timing on the reversal of deferred tax liabilities and future taxable income in the U.S. and in Canada and available tax planning strategies.

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10. Equity compensation plans

Long term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the three months ended March 31, 2019:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2018	3,952,201	2.09
Granted	1,714,238	2.72
Vested and redeemed	(1,782,485)	2.06
Forfeitures	(9,464)	2.07
Outstanding at March 31, 2019	3,874,490	$ 2.38

On March 29, 2019, the compensation committee of our board of directors determined that all notional shares granted under the LTIP held by non-officer employees will be settled in cash following vesting, rather than two-thirds in common shares and one-third in cash. As a result of the modification, all future vesting of notional units for this employee group will be settled in cash. Prior to the modification, vested notional units were settled two-thirds in common shares and one-third in cash, which was utilized to pay employee withholding tax. The portion of LTIP grants settled in common shares was accounted for as equity awards. On the modification date, the equity awards were reclassified as liability awards and a liability equal to the modification-date fair value was recognized. The impact of the modification was not material.

There were no cash payments made for vested notional units for the three months ended March 31, 2019 and 2018. Compensation expense for LTIP and Transition Equity Participation Agreement notional shares was $1.4 million and $0.5 million for the three months ended March 31, 2019 and 2018, respectively.

Transition Equity Participation Agreement

We also have 269,902 transition notional shares outstanding at March 31, 2019 under the Transition Equity Participation Agreement with James J. Moore, Jr. These notional shares will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (Cdn$3.18) by at least 50% (Cdn$4.77).

11. Basic and diluted earnings per share

Basic earnings per share is calculated by dividing net income attributable to Atlantic Power Corporation by the weighted average common shares outstanding during their respective periods. Shares issued and shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted earnings (loss) per share is computed in a manner consistent with that of basic earnings (loss) per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The dilutive effect of our convertible debentures is calculated using the “if-converted method.” Under the if-converted method, the debentures are assumed to be converted at the beginning of the period, and the resulting common shares are included in the denominator of the diluted earnings (loss) per share calculation for the entire period being presented. Interest expense, net of any income tax effects, would be added back to the numerator for purposes of the if-converted calculation. The outstanding equity compensation for non-vested LTIP and Transition Equity Participation Agreement notional shares are not considered outstanding for purposes

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of computing basic earnings per share. However, these instruments are included in the denominator, when dilutive, for purposes of computing diluted earnings per share under the treasury stock method.

The following table sets forth the calculation of basic and diluted earnings per share for the three months ended March 31, 2019 and 2018:

	Three Months Ended March 31,	
Basic	2019	2018
Numerator:		
Income attributable to Atlantic Power Corporation	$ 8.9	$ 15.9
Denominator:		
Weighted average basic shares outstanding	108.9	114.8
Basic earnings per share attributable to Atlantic Power Corporation	$ 0.08	$ 0.14
Diluted		
Numerator:		
Net income attributable to Atlantic Power Corporation	$ 8.9	$ 15.9
Add: convertible debenture interest expense	1.3	0.9
	10.2	16.8
Denominator:		
Weighted average basic shares outstanding	108.9	114.8
Convertible debentures	29.1	22.7
Share-based compensation	0.6	3.1
	138.6	140.6
Diluted earnings per share attributable to Atlantic Power Corporation	$ 0.07	$ 0.12

12. Equity

The following table provides a reconciliation of the beginning and ending equity attributable to shareholders of Atlantic Power Corporation, preferred shares issued by a subsidiary company and total equity for the three months ended March 31, 2019 and 2018:

	Three months ended March 31, 2019		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity
Balance at January 1, 2019	$ (6.9)	$ 199.3	$ 192.4
Net income (loss)	8.9	(6.5)	2.4
Realized and unrealized loss on hedging activities, net of tax	(0.1)	—	(0.1)
Foreign currency translation adjustment	2.2	—	2.2
Common share repurchases	(0.1)	—	(0.1)
Preferred share repurchases	—	(7.7)	(7.7)
Share-based compensation	0.6	—	0.6
Dividends declared on preferred shares of a subsidiary company	—	(1.9)	(1.9)
Balance at March 31, 2019	$ 4.6	$ 183.2	$ 187.8

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	Three months ended March 31, 2018		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity
Balance at January 1, 2018	$ (18.4)	$ 215.2	$ 196.8
Net income (loss)	15.9	(1.7)	14.2
Realized and unrealized gain on hedging activities, net of tax	0.3	—	0.3
Foreign currency translation adjustment	(4.6)	—	(4.6)
Common share repurchases	(6.4)	—	(6.4)
Preferred share repurchases	—	(4.0)	(4.0)
Share-based compensation	0.5	—	0.5
Dividends declared on preferred shares of a subsidiary company	—	(2.2)	(2.2)
Balance at March 31, 2018	$ (12.7)	$ 207.3	$ 194.6

Share Repurchase Program

On December 31, 2018, we commenced a new Normal Course Issuer Bid ("NCIB") for each of our Series D and Series E Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. ("APPEL"), our wholly-owned subsidiary. The NCIBs expire on December 30, 2019 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the NCIB, we may purchase up to a total of 10,623,464 common shares based on 10% of our public float as of December 17, 2018 and we are limited to daily purchases of 10,300 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of

1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval. For the three months ended March 31, 2019, we repurchased and cancelled 0.1 million common shares.

In the three months ended March 31, 2019, we repurchased and cancelled 427,500 shares of 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares"), 78,577 shares of 7.0% Cumulative Rate Preferred Shares Series 2 (the "Series 2 Shares") and 148,311 shares of Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of APPEL at a total cost of $7.7 million. With these repurchases, we reached the 10% limit on Series 1 and Series 3 repurchases under this NCIB. As a result of the repurchase, an $8.4 million loss was attributed to the preferred shares of a subsidiary company in the Consolidated Statements of Operations for the three months ended March 31, 2019.

The Board authorization permits the Company to repurchase common and preferred shares and convertible debentures. Therefore, in addition to the current NCIBs, from time to time we may repurchase our securities, including our common shares, our convertible debentures and our APPEL preferred shares through open market purchases, including pursuant to one or more "Rule 10b5-1 plans" pursuant to such provision under the United States Securities Exchange Act of 1934, as amended, NCIBs, issuer self tender or substantial issuer bids, or in privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions, other market opportunities and other factors. Any share repurchases outside of previously authorized NCIBs would be effected after taking into account our then current cash position and then anticipated cash obligations or business opportunities.

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13. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We analyze the performance of our operating segments based on Project Adjusted EBITDA, which is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. We use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented as proportionately consolidated based on our ownership percentage in the reconciliation of Project Adjusted EBITDA to project income.

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A reconciliation of Project Adjusted EBITDA to net income for the three months ended March 31, 2019 and 2018 is included in the tables below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended March 31, 2019					
Project revenues	$ 44.1	$ 7.8	$ 20.9	$ 0.2	$ 73.0
Segment assets	582.5	167.7	182.4	86.7	1,019.3
Project Adjusted EBITDA	$ 36.0	$ 6.1	$ 11.7	$ (0.1)	$ 53.7
Change in fair value of derivative instruments	0.2	—	0.4	1.8	2.4
Depreciation and amortization	11.5	5.8	2.8	0.1	20.2
Interest, net	0.7	—	—	—	0.7
Other project income	—	(0.1)	(0.1)	—	(0.2)
Project income (loss)	23.6	0.4	8.6	(2.0)	30.6
Administration	—	—	—	6.8	6.8
Interest expense, net	—	—	—	11.1	11.1
Foreign exchange loss	—	—	—	5.0	5.0
Other expense, net	—	—	—	4.7	4.7
Income (loss) before income taxes	23.6	0.4	8.6	(29.6)	3.0
Income tax expense	—	—	—	0.6	0.6
Net income (loss)	$ 23.6	$ 0.4	$ 8.6	$ (30.2)	$ 2.4

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended March 31, 2018					
Project revenues	$ 41.6	$ 13.6	$ 24.6	$ 0.2	$ 80.0
Segment assets	629.2	173.5	221.7	88.7	1,113.1

Project Adjusted EBITDA	$ 33.2	$ 6.1	$ 14.2	$ (0.1)	$ 53.4
Change in fair value of derivative instruments	(0.2)	—	(1.2)	(2.4)	(3.8)
Depreciation and amortization	11.6	8.1	8.0	0.2	27.9
Interest, net	1.0	—	—	—	1.0
Project income (loss)	20.8	(2.0)	7.4	2.1	28.3
Administration	—	—	—	6.0	6.0
Interest expense, net	—	—	—	15.1	15.1
Foreign exchange gain	—	—	—	(8.2)	(8.2)
Other income, net	—	—	—	(2.0)	(2.0)
Income (loss) before income taxes	20.8	(2.0)	7.4	(8.8)	17.4
Income tax expense	—	—	—	3.2	3.2
Net income (loss)	$ 20.8	$ (2.0)	$ 7.4	$ (12.0)	$ 14.2

The table below provides information, by country, about our consolidated operations for each of the three months ended March 31, 2019 and 2018 and Property, Plant & Equipment as of March 31, 2019 and December 31, 2018, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

	Project Revenue Three Months Ended March 31,		Property, Plant and Equipment, net of accumulated depreciation	
	2019	2018	March 31, 2019	December 31, 2018
United States	$ 52.1	$ 55.4	$ 389.5	$ 396.5
Canada	20.9	24.6	154.0	153.0
Total	$ 73.0	$ 80.0	$ 543.5	$ 549.5

Concentration risk

Niagara Mohawk, Independent Electricity System Operator (“IESO”), BC Hydro and Equistar Chemicals, LP provided 20.1%, 15.2%, 12.7% and 12.5%, respectively, of total consolidated revenues for the three months ended March 31, 2019. BC Hydro, Equistar Chemicals, LP, Niagara Mohawk and IESO provided 16.1%, 12.0%, 11.3% and 11.2%, respectively, of total consolidated revenues for the three months ended March 31, 2018. Niagara Mohawk purchases electricity from the Curtis Palmer project in the East U.S. segment, IESO purchases electricity from the Calstock and Nipigon projects, Equistar Chemicals, LP purchases electricity from the Morris project in the East U.S. segment, and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment.

14. Guarantees and Contingencies

Guarantees

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

Contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of March 31, 2019.

15. Leases

Real estate leases and equipment leases

We lease our office properties and equipment under operating leases expiring on various dates through 2024. Certain operating lease agreements include provisions for scheduled rent increases over their lease terms. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. Two of our leased office properties are sub-leased to third parties. These sub-leases are operating leases and the rental income received is recorded net of rental expense in the Consolidated Statements of Operations.

In the fourth quarter of 2018, we made a down payment for the acquisition of two biomass plants in South Carolina, which is expected to close late in the third quarter or in the fourth quarter of 2019. We may acquire real estate,

ATLANTIC POWER CORPORATION

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(Unaudited)

equipment leases or recognize contracts as leases due to this transaction; however, we do not have sufficient information to make any determination as of March 31, 2019.

On January 1, 2019, we implemented FASB ASU No. 2016-02, Leases (Topic 842). To calculate lease liabilities on the implementation date, we utilized an incremental borrowing rate of 3.75%, which is our all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The following table provides our weighted-average remaining lease term and future minimum operating lease commitments.

	Operating Leases Operating Lease Liability As of March 31, 2019	Months remaining on the Lease	Weighted average in months
Real Estate and Equipment leases	$6.6	131.0	53.6

	Income from subleasing	Future minimum lease commitments	Net lease obligations
2019	$0.8	$(1.3)	$(0.5)
2020	1.1	(1.4)	(0.3)
2021	1.1	(1.4)	(0.3)
2022	1.1	(1.4)	(0.3)
2023	0.7	(1.0)	(0.3)
Thereafter	—	(0.1)	(0.1)
	$4.8	$(6.6)	$(1.8)

We have no lease transactions with related parties. We did not utilize practical expedients for separating lease components for all operating leases that we lease.

PPA Leases

We have entered into PPAs to sell power at predetermined rates. PPAs were assessed as to whether they contain leases, which convey to the counterparty the right to control the use of the project's property, plant and equipment in return for future payments. Such arrangements are classified as either operating or finance leases. We recognize lease income consistent with the recognition of energy sales and capacity revenue. When energy is delivered and capacity is provided, we recognize lease income as a component of energy sales and capacity revenue. Finance income related to leases or arrangements accounted for as finance leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income (loss) over the lease term. We elected the practical expedient that permits us to retain our existing lease assessment and classification.

As of March 31, 2019, we have 10 PPAs accounted for as operating leases and one PPA accounted as a direct financing lease among our 17 projects in operation. No extension terms exist for our PPAs accounted for as leases and the remaining lease term varies from six months to 18 years. At March 31, 2019, a net investment in lease of $2.5 million ($2.1 million current and $0.4 million long-term) is recorded as a component of other current assets and other

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ATLANTIC POWER CORPORATION

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(in millions of U.S. dollars, except per share amounts)

(Unaudited)

assets on the consolidated balance sheets for our our direct financing lease. The following table provides lease income recorded as energy and capacity sales by segment from PPAs accounted for as operating leases:

	Rental Income from operating leases Three Months Ended March 31,	
	2019	2018
East U.S.	$ 26.8	$ 24.1
West U.S.	5.5	4.7
Canada	12.1	16.0
	$ 44.4	$ 44.8

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FORWARD LOOKING INFORMATION

Certain statements in this Quarterly Report on Form 10 Q constitute “forward looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Forward looking statements generally can be identified by the use of forward looking terminology such as “outlook,” “objective,” “may,” “will,” “expect,” “intend,” “estimate,” “anticipate,” “should,” “plans,” “continue,” or similar expressions suggesting future outcomes or events. Examples of such statements in this Quarterly Report on Form 10 Q include, but are not limited to, statements with respect to the following:

· our ability to generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities;

· the outcome or impact of our business strategy to increase our intrinsic value on a per-share basis through disciplined management of our balance sheet and cost structure and investment of our discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities;

· our ability to renew or enter into new PPAs on favorable terms or at all after the expiration of our current agreements;

· our ability to meet the financial covenants under our senior secured term loans and other indebtedness;

· our ability to ensure that our plants operate safely and effectively;

· expectations regarding maintenance and capital expenditures; and

· the impact of legislative, regulatory, competitive and technological changes.

Such forward looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Quarterly Report on Form 10 Q. Such forward looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward looking statement made by us or on our behalf.

Forward looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors" in our Annual Report on Form 10 K for the year ended December 31, 2018 and in this Quarterly Report on Form 10 Q. To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2018 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updates to our business strategy, such risk factors should be read in light of such information. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- the expiration or termination of PPAs and our ability to renew or enter into new PPAs on favorable terms or at all;

- our ability to service our debt obligations or generate sufficient cash flow to pay preferred dividends;

- our ability to access liquidity for the ongoing operation of our business and the execution of our business plan or any potential options, which may involve one or more of the use of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non recourse operating level debt;

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- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our senior secured term loans;
- exchange rate fluctuations;
- the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;
- unstable capital and credit markets;
- the dependence of our projects on their electricity and thermal energy customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- the dependence of our projects on third-party suppliers;
- projects not operating according to plan;
- the effects of weather, which affects demand for electricity and fuel as well as operating conditions;
- U.S., Canadian and/or global economic conditions and uncertainty;
- risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;
- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- the impact of impairment of goodwill, long lived assets or equity method investments;
- the impact of failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002;

- increased competition, including for acquisitions;
- our limited control over the operation of certain minority owned projects;
- transfer restrictions on our equity interests in certain projects;
- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and
- our ability to retain, motivate and recruit executives and other key employees.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward looking information include third-party projections of regional fuel and electric capacity and energy prices that are based on assumptions about future economic conditions and courses of action. Although the forward looking statements contained in this Quarterly Report on Form 10 Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward looking statements, and

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the differences may be material. Certain statements included in this Quarterly Report on Form 10 Q may be considered “financial outlook” for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10 Q. These forward looking statements are made as of the date of this Quarterly Report on Form 10 Q and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion of the financial condition and results of operations of Atlantic Power should be read in conjunction with the interim consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10 Q. All dollar amounts discussed below are in millions of U.S. dollars except per share amounts, or unless otherwise stated. The interim financial statements have been prepared in accordance with GAAP.

OVERVIEW

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long term PPAs, which seek to minimize exposure to changes in commodity prices. As of March 31, 2019, our portfolio consisted of seventeen operating projects with an aggregate electric generating capacity of approximately 1,598 megawatts (“MW”) on a gross ownership basis and approximately 1,252 MW on a net ownership basis. Fourteen of the projects are majority owned by the Company.

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). Our PPAs have expiration dates ranging from September 30, 2019 to March 31, 2037. We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

We directly operate and maintain fourteen of our operating power generation projects We also partner with recognized leaders in the independent power industry to operate and maintain our other projects. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

RECENT DEVELOPMENTS

Convertible Debenture Redemption

On April 10, 2019, we redeemed, in full, the aggregate principal amount of Cdn$24.7 million of the outstanding Series D Debentures and paid accrued interest of Cdn$0.4 million.

Credit Rating

On March 27, 2019, S&P Global Ratings affirmed our B+ corporate credit rating and revised our outlook to positive from stable.

Share Repurchase Program

In the three months ended March 31, 2019, we repurchased and cancelled 427,500 Series 1 Shares, 78,577 Series 2 Shares and 148,311 Series 3 Shares of APPEL at a total cost of $7.7 million. With these repurchases, we reached the 10% limit on Series 1 and Series 3 repurchases under this NCIB. We also paid $0.1 million in the three months ended March 31, 2019 to repurchase and cancel common shares As a result of the repurchase, an $8.4 million loss was attributed to the preferred shares of a subsidiary company in the three months ended March 31, 2019.

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OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of May 1, 2019, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. Our customers are generally large utilities and other parties with investment grade credit ratings, as measured by Standard & Poor's ("S&P"). For customers rated by Moody's, we substitute the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment grade have weaker capacity. Agency ratings are subject to change, and there can be no assurance that a rating agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	C C R (
East U.S. Segment								
Orlando(1)	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December 2023	
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September 2032	
Morris (2)	Illinois	Natural Gas	177	100.00 %	100	Merchant	N/A	
					77	Equistar Chemicals, LP (3)	December 2034	
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	
Chambers(1)	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric (5)	March 2024	
					16	Chemours Co.	March 2024	
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2020 (6)	
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 (7)	
West U.S. Segment								
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	May 2020 (8)	
Manchief (9)	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022	

Frederickson(1)	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August 2022
					45	Grays Harbor PUD	August 2022
					30	Franklin Co. PUD	August 2022
Koma Kulshan	Washington	Hydro	13	100.00 %	13	Puget Sound Energy	March 2037
Canada Segment							
Mamquam(10)	British Columbia	Hydro	50	100.00 %	50	British Columbia Hydro and Power Authority	September 2027
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	British Columbia Hydro and Power Authority	August, 2022
Williams Lake	British Columbia	Biomass	66	100.00 %	66	British Columbia Hydro and Power Authority	September 2019
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June 2020
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December 2022
Tunis	Ontario	Natural Gas	37	100.00 %	37	Independent Electricity System Operator	October 2033

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

(2) Equistar has an option to purchase Morris that is exercisable in December 2020 and in December 2027.

(3) Equistar has the right under the PPA to take up to 77 MW, but on average has taken approximately 50 MW.

(4) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals, as Equistar is not rated.

(5) The base PPA with Atlantic City Electric ("ACE") makes up the majority of the revenue from the 89 Net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.

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(6) In January 2019, Merck exercised the second of its three successive one-year options under the PPA for Kenilworth, extending its expiration date from September 30, 2019 to September 30, 2020. Merck has an additional one-year extension option that, if exercised, would extend the PPA expiration date to September 30, 2021.

(7) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through March 31, 2019, the facility has generated 7,767 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

(8) Oxnard's steam sales agreement expires in February 2020.

(9) Public Service Company of Colorado has an option to purchase Manchief that is exercisable in May 2020 and in May 2021.

(10) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021 and every five-year anniversary thereafter.

The following table outlines our power generating assets not currently in operation or under contract:

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
West U.S. Segment								
Naval Station	California	Natural Gas	47	100.00%	47	N/A	(1)	N/A
Naval Training Center	California	Natural Gas	25	100.00%	25	N/A	(1)	N/A
North Island	California	Natural Gas	40	100.00%	40	N/A	(1)	N/A
Canada Segment								
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	N/A	N/A	N/A
North Bay	Ontario	Natural Gas	40	100.00%	40	N/A	N/A	N/A

(1) In August 2018, we terminated discussions with the Navy regarding site control for Naval Station, Naval Training Center ("NTC") and North Island. We are in the process of decommissioning all three sites and expect to complete the process during 2019, which is a requirement of our land use agreements with the Navy.

Consolidated Overview and Results of Operations

Performance highlights

The following table provides a summary of our consolidated results of operations for the three months ended March 31, 2019 and 2018, which are analyzed in greater detail below:

	Three months ended March 31, 2019	2018
Project revenue	$ 73.0	$ 80.0
Project income	$ 30.6	$ 28.3
Net income attributable to Atlantic Power Corporation	$ 8.9	$ 15.9
Earnings per share attributable to Atlantic Power Corporation—basic	$ 0.08	$ 0.14
Earnings per share attributable to Atlantic Power Corporation—diluted	$ 0.07	0.12
Project Adjusted EBITDA(1)	$ 53.7	$ 53.4

(1) See reconciliation and definition in Supplementary Non GAAP Financial Information.

Project revenue decreased by $7.0 million to $73.0 million in the three months ended March 31, 2019 from $80.0 million in the three months ended March 31, 2018. The primary drivers of the decrease are as follows:

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· San Diego projects – the Naval Station, NTC and North Island projects ceased operations in February 2018. This resulted in a $7.4 million decrease in project revenue; and

· Williams Lake – the energy purchase agreement extension became effective in April 2018, which provides lower pass-through of costs than the previous contract. The project also had lower dispatch than the comparable 2018 period. These factors resulted in a $4.2 million decrease in project revenue.

These decreases in project revenue were partially offset by increases in project revenue resulting from:

· Curtis Palmer – higher water flows resulted in a $2.8 million increase in revenue from the comparable 2018 period; and

· Tunis – the project commenced its restart in October 2018 and recorded $1.1 million of revenue in the three months ended March 31, 2019.

Consolidated project income increased by $2.3 million to $30.6 million in the three months ended March 31, 2019 from 28.3 million in the three months ended March 31, 2018. The primary drivers of the increase are as follows:

· Depreciation and amortization expense – depreciation and amortization expense decreased by $7.6 million from the comparable 2018 period primarily due to a decrease of $5.5 million at our Nipigon project resulting from the PPA intangible asset being fully amortized in 2018 and a $2.6 million decrease at the San Diego projects, which ceased operations in February 2018;

· Operation and maintenance expenses – operation and maintenance expenses decreased by $4.8 million from the comparable 2018 period primarily due to a decrease of $2.4 million maintenance expense at our Tunis project where costs were incurred in the comparable 2018 period in preparation for the commencement of its commercial operation; and

· Fuel expense – fuel expense decreased $2.2 million from the comparable 2018 period primarily due to a $4.2 million decrease at the San Diego projects, which ceased operations in February 2018, partially offset by $1.0 million of increased fuel costs at our Williams Lake project due to higher wood fuel cost.

These increases in project income were partially offset by a decrease in project income resulting from:

- Project revenue – project revenue decreased $7.0 million as discussed above; and

- Fuel swap and natural gas purchase agreements – the change in fair value of our derivative instruments decreased $6.1 million from the comparable 2018 period.

A detailed discussion of project income by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 41.

We have four reportable segments: East U.S., West U.S., Canada and Un Allocated Corporate. The segment classified as Un allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project income is the primary GAAP measure of our operating results and is discussed below by reportable segment.

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Three months ended March 31, 2019 compared to the three months ended March 31, 2018

The following table provides our consolidated results of operations:

	Three months ended March 31, 2019	2018	$ change	% change	
Project revenue:					
Energy sales	$ 37.0	$ 38.4	$ (1.4)	(3.6)	%
Energy capacity revenue	30.2	20.1	10.1	50.2	%
Other	5.8	21.5	(15.7)	(73.0)	%
	73.0	80.0	(7.0)	(8.8)	%
Project expenses:					
Fuel	20.0	22.2	(2.2)	(9.9)	%
Operations and maintenance	16.5	21.2	(4.7)	(22.2)	%
Depreciation and amortization	16.2	23.8	(7.6)	(31.9)	%
	52.7	67.2	(14.5)	(21.6)	%
Project other income:					
Change in fair value of derivative instruments	(2.4)	3.8	(6.2)	NM (1)	
Equity in earnings of unconsolidated affiliates	12.9	12.3	0.6	4.9	%
Interest, net	(0.3)	(0.6)	0.3	(50.0)	%
Other income, net	0.1	—	0.1	NM	
	10.3	15.5	(5.2)	(33.5)	%
Project income	30.6	28.3	2.3	8.1	%
Administrative and other expenses:					
Administration	6.8	6.0	0.8	13.3	%
Interest expense, net	11.1	15.1	(4.0)	(26.5)	%
Foreign exchange loss (gain)	5.0	(8.2)	13.2	NM	
Other expense (income), net	4.7	(2.0)	6.7	NM	
	27.6	10.9	16.7	NM	
Income from operations before income taxes	3.0	17.4	(14.4)	(82.8)	%
Income tax expense	0.6	3.2	(2.6)	(81.3)	%
Net income	2.4	14.2	(11.8)	NM	
Net loss attributable to preferred shares of a subsidiary company	(6.5)	(1.7)	(4.8)	NM	
Net income attributable to Atlantic Power Corporation	$ 8.9	$ 15.9	$ (7.0)	(44.0)	%

(1) NM is defined as “not meaningful” and includes changes greater than 100%.

Three months ended March 31, 2019				
East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total

Project revenue:					
Energy sales	$ 26.8	$ 2.9	$ 7.3	$ —	$ 37.0
Energy capacity revenue	12.4	5.0	12.8	—	30.2
Other	4.9	(0.1)	0.8	0.2	5.8
	44.1	7.8	20.9	0.2	73.0
Project expenses:					
Fuel	13.7	1.8	4.5	—	20.0
Operations and maintenance	7.6	3.8	4.7	0.4	16.5
Depreciation and amortization	9.2	4.2	2.8	—	16.2
	30.5	9.8	12.0	0.4	52.7
Project other income (expense):					
Change in fair value of derivative instruments	(0.2)	—	(0.4)	(1.8)	(2.4)
Equity in earnings of unconsolidated affiliates	10.5	2.4	—	—	12.9
Interest expense, net	(0.3)	—	—	—	(0.3)
Other income, net	—	—	0.1	—	0.1
	10.0	2.4	(0.3)	(1.8)	10.3
Project income (loss)	$ 23.6	$ 0.4	$ 8.6	$ (2.0)	$ 30.6

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	Three months ended March 31, 2018				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 25.3	$ 5.1	$ 8.0	$ —	$ 38.4
Energy capacity revenue	11.3	5.9	2.9	—	20.1
Other	5.0	2.6	13.7	0.2	21.5
	41.6	13.6	24.6	0.2	80.0
Project expenses:					
Fuel	13.6	5.4	3.2	—	22.2
Operations and maintenance	8.2	5.6	7.1	0.3	21.2
Depreciation and amortization	9.1	6.5	8.1	0.1	23.8
	30.9	17.5	18.4	0.4	67.2
Project other income (expense):					
Change in fair value of derivative instruments	0.3	—	1.2	2.3	3.8
Equity in earnings of unconsolidated affiliates	10.4	1.9	—	—	12.3
Interest expense, net	(0.6)	—	—	—	(0.6)
	10.1	1.9	1.2	2.3	15.5
Project income (loss)	$ 20.8	$ (2.0)	$ 7.4	$ 2.1	$ 28.3

East U.S.

Project income for the three months ended March 31, 2019 increased $2.8 million from the comparable 2018 period primarily due to:

· increased project income of $2.7 million at Curtis Palmer primarily due to higher water flows than the comparable 2018 period.

West U.S.

Project income for the three months ended March 31, 2019 increased $2.4 million from a project loss in the comparable 2018 period primarily due to:

· decreased project loss of $0.8 million, $0.6 million and $0.5 million at Naval Station, NTC and North Island, which ceased operations in February 2018; and

· increased project income of $0.5 million at Manchief primarily due to a $0.4 million increase in project revenue from higher dispatch than the comparable 2018 period.

Canada

Project income for the three months ended March 31, 2019 increased $1.2 million from the comparable 2018 period primarily due to:

· increased project income of $4.1 million at Nipigon primarily due to a $5.4 million decrease in amortization expense from accelerated amortization of the intangible PPA asset in the comparable 2018 period, partially offset by a $1.6 million decrease in fair value of fuel purchase agreements; and

· increased project income of $3.2 million at Tunis primarily due to a $2.4 million decrease in maintenance expense in preparation of commencing operations in October 2018.

These increases were partially offset by:

· decreased project income of $5.0 million at Williams Lake primarily due to a $4.3 million decrease in project revenue from the terms of the renewed energy purchase agreement extension that became effective in April 2018; and

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· decreased project income of $0.5 million at Mamquam primarily due to lower water flows than the comparable 2018 period.

Un allocated Corporate

Project income for the three months ended March 31, 2019 decreased $4.1 million from the comparable 2018 period primarily due to a $4.1 million decrease in change in fair value of interest swaps related to the senior secured credit facility.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to any specific project and is allocated to the Un allocated Corporate segment. These costs include the activities that support the executive and administrative offices, treasury function, costs of being a public registrant, costs to develop or acquire future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate taxes. Significant non cash items that impact Administrative and other expenses (income), and that are subject to potentially significant fluctuations include the non cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar denominated obligations and the related deferred income tax expense (benefit) associated with these non cash items.

Administration

Administration expense increased by $0.8 million to $6.8 million in the three months ended March 31, 2019 from $6.0 million in the comparable 2018 period due to $0.9 million of higher employee stock-based compensation expense.

Interest expense, net

Interest expense decreased by $4.1 million to $11.0 million in the three months ended March 31, 2019 from $15.1 million in the comparable period in 2018, primarily due to lower outstanding debt balances than the comparable 2018 period, as well as a lower interest rate on our senior secured credit facility.

Foreign exchange loss (gain)

Foreign exchange gain decreased by $13.2 million to a $5.0 million loss in the three months ended March 31, 2019 from an $8.2 million gain in the comparable 2018 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs) and convertible debentures). The Canadian dollar appreciated 2.0% against the U.S. dollar from December 31, 2018 to March 31, 2019, as compared to a 2.8% depreciation in the comparable 2018 period.

Other expense, net

Other expense increased by $6.7 million from $2.0 million other income in the comparable 2018 period primarily due to a $6.8 million decrease in the fair value of the convertible debenture conversion option.

Income tax expense

Income tax expense for the three months ended March 31, 2019 was $0.6 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $0.8 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 which have been reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, base erosion and anti-abuse tax. Based on estimates as of the date of this filing, we will not be subject to the base erosion and anti-abuse tax. Our interest expense deduction may be limited, but will not have a material impact on cash taxes. The primary item impacting the tax rate for the three months ended March 31, 2019 was a net decrease to our valuation allowances of $1.6 million, consisting of a

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$1.7 million increase in Canada and $3.3 million decreases in the United States due to income. These items were partially offset by $0.7 million relating to foreign exchange, $0.4 million relating to withholding state taxes and $0.3 million of other permanent differences.

Income tax expense for the three months ended March 31, 2018 was $3.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $4.5 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the Internal Revenue Code. Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 which have been reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, and base erosion and anti-abuse tax. Based on estimates as of the date of this filing, the interest expense limitation and base erosion and anti-abuse tax will not have a material impact on cash taxes. The primary items impacting the tax rate for the three months ended March 31, 2018 was a net increase to our valuation allowances of $0.8 million, consisting of an $0.8 million increase in Canada related to losses and no change in the United States for the three months ended March 31, 2018. In addition, the rate was further impacted by $0.1 million of other permanent differences. These items were offset by $1.3 million relating to capital loss on intercompany notes and $0.9 million relating to changes in tax rates.

Project Operating Performance

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours (“MWh”). Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was not material for the three months ended March 31, 2019. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in net Gigawatt hours (“net GWh”).

Generation

	Three months ended March 31,			
(in Net GWh)	2019	2018	% change 2019 vs. 2018	
Segment				
East U.S.	650.2	656.2	(0.9)	%
West U.S.	307.5	243.3	26.4	%
Canada	214.3	221.0	(3.0)	%
Total	1,172.0	1,120.5	4.6	%

Three months ended March 31, 2019 compared with three months ended March 31, 2018

Aggregate power generation for the three months ended March 31, 2019 increased 4.6% from the comparable 2018 period primarily due to:

· increased generation in the West U.S. segment primarily due to a 115.1 net GWh increase in generation at Frederickson due to higher dispatch than the comparable 2018 period and a 43.4 net GWh increase in generation at Manchief due to higher dispatch than the comparable 2018 period, partially offset by a combined 95.5 net GWh decrease in generation at Naval Station, NTC and North Island, which ceased operations in February 2018.

These increases were partially offset by:

· decreased generation in the Canada segment primarily due to an 11.4 net GWh decrease in generation at Mamquam due to lower water flows; and

· decreased generation in the East U.S. segment primarily due to a 21.8 net GWh decrease in generation at Chambers due to lower merchant pricing, offset by a 19.9 net GWh increase in generation at Curtis Palmer due to higher water flows.

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Availability

	Three months ended March 31,		% change
	2019	2018	2019 vs. 2018
Segment			
East U.S.	98.6 %	98.0 %	0.6 %
West U.S. (1)	96.7 %	97.2 %	(0.5) %
Canada	97.2 %	99.7 %	(2.5) %
Weighted average	97.9 %	98.3 %	(0.4) %

(1) The San Diego projects, which ceased operations in February 2018, have been excluded from availability in both 2019 and 2018.

Three months ended March 31, 2019 compared with three months ended March 31, 2018

Aggregate power availability for the three months ended March 31, 2019 decreased 0.4% from the comparable 2018 period primarily due to:

- decreased availability in the Canada segment primarily due to a maintenance outage at Mamquam, partially offset by a newly enacted long-term enhanced dispatch agreement at Nipigon and operation commencing at Tunis in October 2018; and

- decreased availability in the West U.S. segment primarily due to a maintenance outage at Oxnard.

Supplementary Non GAAP Financial Information

The key measurement we use to evaluate the results of our business is Project Adjusted EBITDA. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We believe that Project Adjusted EBITDA is a useful measure of financial results at our projects because it excludes non-cash impairment charges, gains or losses on the sale of assets and non-cash mark-to-market adjustments, all of which can affect year-to-year comparisons. Project Adjusted EBITDA is before corporate overhead expense. The most directly comparable GAAP measure to Project Adjusted EBITDA is Project income. A reconciliation of Net income (loss) to Project income and to Project Adjusted EBITDA is provided under “Project Adjusted EBITDA” below. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

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Project Adjusted EBITDA

	Three months ended March 31, 2019	2018	$ change 2019 vs 2018
Net income	$ 2.4	$ 14.2	$ (11.8)
Income tax expense	0.6	3.2	(2.6)
Income from operations before income taxes	3.0	17.4	(14.4)
Administration	6.8	6.0	0.8
Interest expense, net	11.1	15.1	(4.0)
Foreign exchange loss (gain)	5.0	(8.2)	13.2
Other expense (income), net	4.7	(2.0)	6.7
Project income	$ 30.6	$ 28.3	$ 2.3
Reconciliation to Project Adjusted EBITDA			
Depreciation and amortization	20.2	27.9	(7.7)
Interest expense, net	0.7	1.0	(0.3)
Change in the fair value of derivative instruments	2.4	(3.8)	6.2
Other income, net	(0.2)	—	(0.2)
Project Adjusted EBITDA	$ 53.7	$ 53.4	$ 0.3
Project Adjusted EBITDA by segment			
East U.S.	36.0	33.2	2.8
West U.S.	6.1	6.1	—
Canada	11.7	14.2	(2.5)
Un-Allocated Corporate	(0.1)	(0.1)	—
Total	$ 53.7	$ 53.4	$ 0.3

East U.S.

The following table summarizes Project Adjusted EBITDA for our East U.S. segment for the periods indicated:

	Three months ended March 31, 2019	2018	% change 2019 vs. 2018
East U.S.			
Project Adjusted EBITDA	$ 36.0	$ 33.2	8 %

Three months ended March 31, 2019 compared with three months ended March 31, 2018

Project Adjusted EBITDA for the three months ended March 31, 2019 increased $2.8 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $2.7 million at Curtis Palmer due to higher water flows than the comparable 2018 period.

West U.S.

The following table summarizes Project Adjusted EBITDA for our West U.S. segment for the periods indicated:

	Three months ended March 31,		
	2019	2018	% change 2019 vs 2018
West U.S. Project Adjusted EBITDA	$ 6.1	$ 6.1	— %

Three months ended March 31, 2019 compared with three months ended March 31, 2018

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Project Adjusted EBITDA for the three months ended March 31, 2019 did not change materially from the three months ended March 31, 2018.

Canada

The following table summarizes Project Adjusted EBITDA for our Canada segment for the periods indicated:

	Three months ended March 31,			
			% change	
	2019	2018	2019 vs. 2018	
Canada				
Project Adjusted EBITDA	$ 11.7	$ 14.2	(18)	%

Three months ended March 31, 2019 compared with three months ended March 31, 2018

Project Adjusted EBITDA for the three months ended March 31, 2019 decreased $2.5 million from the comparable 2018 period primarily due to decreased Project Adjusted EBITDA of:

· $5.1 million at Williams Lake primarily due to lower gross margin under the short-term contract extension that become effective in April 2018; and

· $0.6 million at Mamquam due to lower water flows than the comparable 2018 period.

These decreases were partially offset by increased Project Adjusted EBITDA of:

· $3.5 million at Tunis due to a $2.4 million decrease in maintenance expense in preparation of commencing operations in October 2018.

Un allocated Corporate

The following table summarizes Project Adjusted EBITDA for our Un allocated Corporate segment for the periods indicated:

	Three months ended March 31,		
			% change
	2019	2018	2019 vs. 2018
Un-allocated Corporate			
Project Adjusted EBITDA	$ (0.1)	$ (0.1)	NM

Three months ended March 31, 2019 compared with three months ended March 31, 2018

Project Adjusted EBITDA for the three months ended March 31, 2019 did not change materially from the comparable 2018 period.

Liquidity and Capital Resources

	March 31, 2019	December 31, 2018
Cash and cash equivalents	$ 74.8	$ 68.3
Restricted cash	0.5	2.1
Total	75.3	70.4
Revolving credit facility availability	123.1	123.1
Total liquidity	$ 198.4	$ 193.5

Overview

Our primary sources of liquidity are distributions from our projects and availability under our Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or

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terminate. PPAs in our portfolio have expiration dates ranging from September 30, 2019 to March 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See “Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities” in our Annual Report on Form 10 K for the year ended December 31, 2018.

We expect to reinvest approximately $25.6 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2019, of which $4.3 million has been incurred through March 31, 2019. Such investments are generally paid at the project level. See “Liquidity and Capital Resources—Capital and Maintenance Expenditures” in our Annual Report on Form 10 K for the year ended December 31, 2018. We expect to pay the remaining $10.4 million of the purchase price for two biomass plants in South Carolina when the transaction closes late in the third quarter or the fourth quarter of 2019. Other than this payment, we do not expect any other material or unusual requirements for cash outflows in 2019 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

Consolidated Cash Flow Discussion

The following table reflects the changes in cash flows for the periods indicated:

	Three months ended March 31,		
	2019	2018	Change
Net cash provided by operating activities	$ 29.2	$ 50.3	$ (21.1)
Net cash provided by (used in) investing activities	1.2	(1.1)	2.3
Net cash used in financing activities	(25.5)	(45.7)	20.2

Operating Activities

Cash flow from our projects may vary from period to period based on working capital requirements and the operating performance of the projects, as well as changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the three months ended March 31, 2019, the net decrease in cash provided by operating activities of $21.1 million was primarily the result of the following:

· Working capital – changes in working capital resulted in a $22.7 million decrease in cash flows from operating activities from the comparable 2018 period. Cash flows from operations in the comparable 2018 period benefitted from an $18.3 million change in working capital at our Kapuskasing, North Bay (expiration of enhanced dispatch agreements on December 31, 2017) and San Diego projects (ceased operations in February 2018); and

· Contract extension – the energy purchase agreement extension at Williams Lake that became effective in April 2018 provides lower pass-through of costs than the previous contract. The project also had lower dispatch than the comparable 2018 period. These factors had a $5.1 million negative impact on cash flows provided by operating activities.

These decreases were partially offset by the following increases to cash flows from operations:

· Tunis operations – the Tunis project commenced commercial operations in October 2018 and recorded revenue of $1.1 million in the three months ended March 31, 2019. Additionally, Tunis incurred $2.7

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million of non-recurring maintenance expense in the comparable 2018 period to prepare the project for commercial operations; and

· Hydrological conditions – higher water flows at our Curtis Palmer project, partially offset by lower water flows at our Mamquam project, had a $2.1 million positive impact on cash flows provided by operating activities.

Investing Activities

For the three months ended March 31, 2019, the net increase in cash provided by investing activities of $2.3 million was primarily the result of the following:

· Proceeds from asset sales – we received $1.5 million of cash proceeds from the sale of equipment at our San Diego projects; and

· Capitalized plant additions – capitalized plant additions were $0.8 million lower in the three months ended March 31, 2019 than the comparable 2018 period.

Financing Activities

For the three months ended March 31, 2019, the net increase in cash used in financing activities of $20.2 million was primarily the result of the following:

· Convertible debenture redemptions – we paid $88.1 million in the comparable 2018 period to redeem and cancel the Series C Debentures, in full, and the Series D Debentures, in part, with proceeds from the issuance of the Series E Debentures;

· Corporate and project-level debt repayments – we made $16.6 million less principal payments than the comparable 2018 period; and

· Common share repurchases – we paid $0.1 million in the three months ended March 31, 2019 to repurchase and cancel common shares as compared to $6.4 million in the comparative 2018 period.

These decreases were partially offset by the following increases to cash flows used in financing activities:

- Convertible debenture issuance – we received $92.2 million from the issuance of the Series E Debentures in the comparable 2018 period;

- Preferred share repurchases – we paid $7.7 million in the three months ended March 31, 2019 to repurchase and cancel preferred shares as compared to $4.0 million in the comparative 2018 period; and

- Deferred financing costs – we incurred $4.8 million of deferred financing costs related to the issuance of the Series E Debentures in the comparable 2018 period.

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Corporate Debt

The following table summarizes the maturities of our corporate debt at March 31, 2019:

	Maturity Date	Interest Rates		Remaining Principal Repayments	2019	2020	2021	2022	2023	Thereafter
Senior secured term loan facility(1)	April 2023	4.12 %	- 5.24 %	$ 435.0	$ 50.0	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ —
MTNs	June 2036	5.95 %		157.1	—	—	—	—	—	157.1
Convertible Debenture (2)	December 2019	6.00 %		18.5	18.5	—	—	—	—	—
Convertible Debenture	January 2025	6.00 %		86.1	—	—	—	—	—	86.1
Total Corporate Debt				$ 696.7	$ 68.5	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ 243.2

(1) The Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of Atlantic Power Limited Partnership Holdings ("APLP Holdings") and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the 5.95% MTNs, letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd. ("APPEL"), a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and APPEL being unable to pay dividends to its shareholders. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above.

(2) On April 10, 2019, we redeemed, in full, the aggregate principal amount of Cdn$24.7 million ($18.5 million) of the outstanding Series D Debentures.

Project Level Debt

Project level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project level debt. The amounts represent our share of the non recourse project level debt balances at March 31, 2019. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. At May 1, 2019, all of our projects were in compliance with the covenants contained in project level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but are not callable or subject to acceleration under the terms of their debt agreements.

The range of interest rates presented represents the rates in effect at March 31, 2019. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Maturity Date	Range of Interest Rates	Total Remaining Principal Repayments	2019	2020	2021	2022	2023	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.26 % - 6.38 %	$ 20.3	$ 2.3	$ 3.1	$ 2.7	$ 3.3	$ 3.3	$ 5.6
Total Consolidated Projects			20.3	2.3	3.1	2.7	3.3	3.3	5.6
Equity Method Projects:									
Chambers(1)	December 2019 and 2023	4.50 % - 5.00 %	42.9	5.2	7.8	8.8	10.1	11.0	—
Total Equity Method Projects			42.9	5.2	7.8	8.8	10.1	11.0	—
Total Project-Level Debt			$ 63.2	$ 7.5	$ 10.9	$ 11.5	$ 13.4	$ 14.3	$ 5.6

(1) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax-exempt) Bonds due December 2023, of which our proportionate share is $41.3 million, and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is $1.6 million. The above table does not include our $4.2 million proportionate share of

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issuance premiums.

Uses of Liquidity

Our requirements for liquidity and capital resources, other than operating our projects, consist primarily of principal and interest on our outstanding convertible debentures, senior secured term loans, MTNs and other corporate and project-level debt, funding the repurchase of shares of our common stock, our convertible debentures, our preferred shares (to the extent we choose to pursue any such repurchases), collateral and investment in our projects through capital expenditures, including major maintenance and business development costs, and dividend payments to preferred shareholders of a subsidiary company.

Capital and Maintenance Expenditures

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On going capital expenditures for assets of this nature are generally not significant because most expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $1.2 million in 2019 (of which $0.3 million was reinvested in the three months ended March 31, 2019) in our portfolio, including equity method investments, in the form of project capital expenditures, and incur $24.4 million of maintenance expenses (of which $4.0 million was incurred in the three months ended March 31, 2019). Such investments are generally paid at the project level. See "Liquidity and Capital Resources—Capital and Maintenance Expenditures" in our Annual Report on Form 10 K for the year ended December 31, 2018. We do not expect any other material or unusual requirements for cash outflows for 2019 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

We believe one of the benefits of our diverse fleet is that plant overhauls and other expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to assess maintenance needs. In addition, we utilize predictive and risk based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and maintenance expenses may exceed the projected level in 2019 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

Recently Adopted and Recently Issued Accounting Guidance

See Note 1 to the consolidated financial statements in this Quarterly Report on Form 10 Q.

Off Balance Sheet Arrangements

As of March 31, 2019, we had no off balance sheet arrangements as defined in Item 303(a)(4) of Regulation S K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to financial market risk results primarily from fluctuations in interest and currency rates and fuel and electricity prices. There have been no material changes to our market risks as disclosed in our Annual Report on Form 10 K for the fiscal year ended December 31, 2018.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures, as defined in R
are effective.

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Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the three months ended March 31, 2019, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent material errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the control may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

ITEM 1A. RISK FACTORS

There were no material changes to the risk factors disclosed in “Item 1A. Risk Factors” of our Annual Report on Form 10 K for the year ended December 31, 2018 except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10 Q relates to such risk factors (including, without limitation, the matters discussed in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations”). To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2018 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updated to our business strategy, such risk factors should be read in light of such information.

ITEM 2: UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

(c) Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Share Repurchase Program

On December 31, 2018, we commenced a new Normal Course Issuer Bid ("NCIB") for each of our Series D and Series E Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. ("APPEL"), our wholly-owned subsidiary. The NCIBs expire on December 30, 2019 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the NCIB, we may purchase up to a total of 10,623,464 common shares based on 10% of our public float as of December 17, 2018 and we are limited to daily purchases of 10,300 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of 1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval. For the three months ended March 31, 2019, we repurchased and cancelled 0.1 million common shares.

In the three months ended March 31, 2019, we repurchased and cancelled 427,500 shares of 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares"), 78,577 shares of 7.0% Cumulative Rate Preferred Shares Series 2 (the "Series 2 Shares") and 148,311 shares of Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of APPEL at a total cost of $7.7 million. With these repurchases, we reached the 10% limit on Series 1 and Series 3 repurchases under this NCIB. As a result of the repurchase, an $8.4 million loss was attributed to the preferred shares of a subsidiary company in the Consolidated Statements of Operations for the three months ended March 31, 2019.

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.1+	Sixth Amended and Restated Long Term Incentive Plan
10.2+	Amendment to Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated as of January 23, 2019
10.3+	Form of Legacy Award Amendment
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

+ Indicates management contract or compensatory plan or arrangement

*Filed herewith.

**Furnished herewith.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: May 2, 2019	Atlantic Power Corporation		
	By:	/s/ Terrence Ronan	
		Name:	Terrence Ronan
		Title:	Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)