ATLANTIC POWER CORP
Form 10-Q
August 03, 2017
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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 June 30, 2017

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 220	
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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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 (Do not check if a smaller reporting company)	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 August 1, 2017 was 115,280,908.

ATLANTIC POWER CORPORATION

FORM 10 Q

SIX MONTHS ENDED JUNE 30, 2017

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GENERAL

In this Quarterly Report on Form 10 Q, references to “Cdn$” and “Canadian dollars” are to the lawful currency of Canada and references to “$” and “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	June 30, 2017 (unaudited)	December 31, 2016
Current assets:		
Cash and cash equivalents	$ 104.4	$ 85.6
Restricted cash	14.1	13.3
Accounts receivable	42.3	37.3
Current portion of derivative instruments asset (Notes 5 and 6)	2.8	4.0
Inventory	19.5	16.0
Prepayments	7.2	5.9
Income taxes receivable	0.5	—
Other current assets	2.9	2.8
Total current assets	193.7	164.9
Property, plant, and equipment, net	705.8	733.2
Equity investments in unconsolidated affiliates (Note 3)	204.2	266.8
Power purchase agreements and intangible assets, net	227.4	246.2
Goodwill	36.0	36.0
Derivative instruments asset (Notes 5 and 6)	2.8	4.6
Other assets	4.2	5.1
Total assets	$ 1,374.1	$ 1,456.8
Liabilities		
Current liabilities:		
Accounts payable	$ 3.3	$ 4.5
Accrued interest	2.0	0.7
Other accrued liabilities	23.9	24.4
Current portion of long-term debt (Note 4)	106.9	111.9
Current portion of derivative instruments liability (Notes 5 and 6)	6.3	7.6
Other current liabilities	3.0	1.8
Total current liabilities	145.4	150.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 4)	707.6	749.2
Convertible debentures, net of unamortized deferred financing costs	102.8	100.4
Derivative instruments liability (Notes 5 and 6)	24.4	21.3
Deferred income taxes	43.6	68.3
Power purchase and fuel supply agreement liabilities, net	24.7	25.3
Other long-term liabilities	56.3	55.5
Total liabilities	1,104.8	1,170.9
Equity		

Common shares, no par value, unlimited authorized shares; 115,280,908 and 114,649,888 issued and outstanding at June 30, 2017 and December 31, 2016	1,274.0	1,272.9
Accumulated other comprehensive loss (Note 2)	(141.6)	(148.5)
Retained deficit	(1,084.4)	(1,059.8)
Total Atlantic Power Corporation shareholders' equity	48.0	64.6
Preferred shares issued by a subsidiary company (Note 10)	221.3	221.3
Total equity	269.3	285.9
Total liabilities and equity	$ 1,374.1	$ 1,456.8

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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Project revenue:				
Energy sales	$ 40.0	$ 45.1	$ 77.1	$ 97.6
Energy capacity revenue	28.3	37.3	47.8	69.2
Other	55.7	15.8	97.5	37.8
	124.0	98.2	222.4	204.6
Project expenses:				
Fuel	24.0	35.1	52.9	74.0
Operations and maintenance	23.3	30.0	43.6	51.2
Depreciation and amortization	29.5	25.5	59.0	50.3
	76.8	90.6	155.5	175.5
Project other income:				
Change in fair value of derivative instruments (Notes 5 and 6)	(2.7)	12.2	(3.9)	11.0
Equity in (loss) earnings of unconsolidated affiliates (Note 3)	(54.4)	7.6	(45.4)	18.3
Interest, net	(2.2)	(2.4)	(4.4)	(4.5)
Other income, net	—	0.2	—	—
	(59.3)	17.6	(53.7)	24.8
Project (loss) income	(12.1)	25.2	13.2	53.9
Administrative and other expenses:				
Administration	5.7	5.8	12.1	11.9
Interest expense, net	18.4	51.2	35.7	67.8
Foreign exchange loss	5.9	2.6	8.3	22.5
Other income (expense), net	—	0.3	—	(2.2)
	30.0	59.9	56.1	100.0
Loss from operations before income taxes	(42.1)	(34.7)	(42.9)	(46.1)
Income tax benefit (Note 7)	(22.3)	(18.4)	(22.6)	(16.8)
Net loss	(19.8)	(16.3)	(20.3)	(29.3)
Net income attributable to preferred shares dividends of a subsidiary company	2.1	2.2	4.3	4.2
Net loss attributable to Atlantic Power Corporation	$ (21.9)	$ (18.5)	$ (24.6)	$ (33.5)

Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 9)				
Basic	$ (0.19)	$ (0.15)	$ (0.21)	$ (0.28)
Diluted	(0.19)	(0.15)	(0.21)	(0.28)
Weighted average number of common shares outstanding: (Note 9)				
Basic	115.2	121.6	115.0	121.8
Diluted	115.2	121.6	115.0	121.8

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in millions of U.S. dollars)

(Unaudited)

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Net loss	$ (19.8)	$ (16.3)	$ (20.3)	$ (29.3)
Other comprehensive loss, net of tax:				
Unrealized loss on hedging activities	$ (0.1)	$ (0.2)	$ (0.3)	$ (0.7)
Net amount reclassified to earnings	0.1	0.2	0.4	0.4
Net unrealized gain (loss) on derivatives	—	—	0.1	(0.3)
Defined benefit plan, net of tax	—	—	0.1	—
Foreign currency translation adjustments	4.7	1.0	6.7	19.4
Other comprehensive income, net of tax	4.7	1.0	6.9	19.1
Comprehensive loss	(15.1)	(15.3)	(13.4)	(10.2)
Less: Comprehensive income attributable to preferred share dividends of a subsidiary company	2.1	2.2	4.3	4.2
Comprehensive loss attributable to Atlantic Power Corporation	$ (17.2)	$ (17.5)	$ (17.7)	$ (14.4)

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)

	Six Months Ended June 30, 2017	2016
Cash provided by operating activities:		
Net loss	$ (20.3)	$ (29.3)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	59.0	50.3
Gain on purchase and cancellation of convertible debentures	—	(2.5)
Loss on disposal of fixed assets	—	0.2
Stock-based compensation expense	1.1	0.8
Equity in loss (earnings) from unconsolidated affiliates	45.4	(18.3)
Distributions from unconsolidated affiliates	17.2	23.5
Unrealized foreign exchange loss	8.3	22.5
Change in fair value of derivative instruments	3.9	(11.0)
Amortization of debt discount and deferred financing costs	5.2	37.5
Change in deferred income taxes	(24.9)	(18.6)
Change in other operating balances		
Accounts receivable	(5.0)	(3.3)
Inventory	(3.4)	(0.4)
Prepayments and other assets	(0.3)	1.7
Accounts payable	(1.4)	3.5
Accruals and other liabilities	0.2	(2.9)
Cash provided by operating activities	85.0	53.7
Cash (used in) provided by investing activities:		
Change in restricted cash	(0.8)	0.9
Reimbursement of costs for third party construction project	—	4.7
Purchase of property, plant and equipment	(4.2)	(2.0)
Cash (used in) provided by investing activities	(5.0)	3.6
Cash (used in) provided by financing activities:		
Proceeds from term loan facility, net of discount	—	679.0
Common share repurchases	—	(4.7)
Repayment of corporate and project-level debt	(56.9)	(502.7)

Repayment of convertible debentures	—	(127.0)
Deferred financing costs	—	(15.9)
Dividends paid to preferred shareholders	(4.3)	(4.2)
Cash (used in) provided by financing activities:	(61.2)	24.5
Net increase in cash and cash equivalents	18.8	81.8
Cash and cash equivalents at beginning of period	85.6	72.4
Cash and cash equivalents at end of period	$ 104.4	$ 154.2
Supplemental cash flow information		
Interest paid	$ 33.4	$ 34.7
Income taxes paid, net	$ 2.2	$ 1.9
Accruals for construction in progress	$ 1.3	$ 1.0

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

1. Nature of business

General

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of June 30, 2017, our power generation projects had an aggregate gross electric generation capacity of approximately 2,138 megawatts ("MW") in which our aggregate ownership interest is approximately 1,500 MW. Our current portfolio consists of interests in twenty-three power generation projects across nine states in the United States and two provinces in Canada. Nineteen of the projects are currently operational, totaling 1,975 MW on a gross capacity basis and 1,337 MW on a net ownership basis. The remaining four projects, all in Ontario, are not operational, three due to revised contractual arrangements with the offtaker and the other, Tunis, has a forward-starting 15-year contractual agreement that will commence between November 2017 and June 2019. Eighteen of our projects are majority owned.

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 under the symbol "ATP" and on the New York Stock Exchange 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 220, 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, 2016. 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 June 30, 2017, the results of operations and comprehensive (loss) income for the three and six months ended June 30, 2017 and 2016, and our cash flows for the six months ended June 30, 2017 and 2016 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

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 useful lives and recoverability of property, plant and 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, 2016. 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 issued accounting standards

Adopted

In July 2015, the FASB issued changes to the subsequent measurement of inventory. Currently, an entity is required to measure its inventory at the lower of cost or market, whereby market can be replacement cost, net realizable value, or net realizable value less an approximately normal profit margin. The changes require that inventory be measured at the lower of cost and net realizable value, thereby eliminating the use of the other two market methodologies. Net realizable value is defined as the estimated selling prices in the ordinary course of business less reasonably predictable costs of completion, disposal, and transportation. These changes became effective for us on January 1, 2017 and did not have an impact on the consolidated financial statements.

In November 2015, the FASB issued changes to the balance sheet classification of deferred taxes. These changes simplify the presentation of deferred income taxes by requiring all deferred income tax assets and liabilities, along with any related valuation allowance, to be classified as noncurrent in a classified balance sheet. The current requirement that deferred tax assets and liabilities of a tax-paying component of an entity be offset and presented as a single amount is not affected by these changes. The new guidance became effective for us on January 1, 2017 and did not have an impact on the consolidated financial statements.

In March 2016, the FASB issued authoritative guidance intended to simplify and improve several aspects of the accounting for share-based payment transactions. The new guidance includes amendments to share-based accounting for forfeitures and income taxes, including adjustments to how excess tax benefits and a company's payments for tax withholdings should be classified in the statement of cash flows. We have elected to continue our policy of estimating forfeitures each period. This guidance became effective for us on January 1, 2017 and did not have an impact on our financial position and results of operations upon its adoption.

Issued

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity will recognize revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. The new disclosure requirements will include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. Entities will generally be

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required to make more estimates and use more judgment under the new standard. The new requirements will be effective for us beginning January 1, 2018, and may be implemented either retrospectively for all periods presented, or as a cumulative-effect adjustment as of January 1, 2018. Early adoption is permitted, but not before January 1, 2017. Management is currently evaluating the potential impact of this new guidance on our consolidated financial statements. We have developed a project plan to assess the potential impact of the standard and have evaluated a sampling of our most significant contracts (PPAs). We have approximately 20 PPAs at our consolidated projects that require further analysis under this standard. Currently we recognize energy revenue upon transmission to the customer. Capacity revenue is recognized when billed as hours are made available under the terms of the relevant PPA. Our current policy appears to be in compliance with the new standard’s focus on when the customer obtains control of the goods or services. However, these agreements are complex and still require significant analysis prior to reaching a conclusion as to how the adoption of the standard will impact our financial position, results of operations and cash flows. Upon adoption, we expect to utilize the cumulative-effect adjustment method upon adoption as of January 1, 2018.

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. The guidance should be applied under a modified retrospective transition approach for leases existing at the beginning of the earliest comparative period presented in the adoption-period financial statements. 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 expect to elect certain of the practical expedients permitted, including the expedient that permits us to retain our existing lease assessment and classification. We are currently working through an adoption plan which includes the evaluation of lease contracts compared to the new standard. While we are currently evaluating the impact the new guidance will have on our financial position and results of operations, we expect to recognize lease liabilities and right of use assets. The extent of the increase to assets and liabilities associated with these amounts remains to be determined pending our review of our existing lease contracts and power purchase agreements currently accounted for as operating leases. As this review is still in process, it is currently not practicable to quantify the impact of adopting this guidance at this time.

In August 2016, the FASB issued authoritative guidance intended to clarify classification of specific cash flows that have aspects of more than one class of cash flows. As a result of this new guidance, entities should be applying specific GAAP in the following eight cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. The guidance is not expected to have a material impact on the consolidated financial statements.

In November 2016, the FASB issued authoritative guidance to address diversity in practice of presenting changes in restricted cash on the statement of cash flows. The new guidance requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. Adoption of this guidance will be applied retrospectively. This guidance will change our presentation of restricted cash in the consolidated statements of cash flows upon adoption. If this guidance was adopted in the six months ended June 30, 2017, cash flows provided by operations would decrease by $0.8 million and cash flows used in investing activities would increase by $0.8 million, and for the six months ended June 30, 2016, cash flows provided by operating activities would increase by $0.9 million and cash flows used in investing activities would decrease by $0.9 million.

In October 2016, the FASB issued authoritative guidance, which amends existing guidance related to the recognition of current and deferred incomes taxes for intra-entity asset transfers. Under the new guidance, current and deferred income tax consequences of an intra-entity asset transfer, other than an intra-entity asset transfer of inventory, are now recognized when the transfer occurs. The guidance is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2017 with early adoption permitted. We are currently evaluating the potential impact of the adoption on the consolidated financial statements.

In January 2017, the FASB issued authoritative guidance, which removes the requirement to perform a hypothetical purchase price allocation to measure goodwill impairment. A goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. This guidance is effective for us for annual and interim periods beginning January 1, 2020, with early adoption permitted, and applied prospectively. We plan to adopt this guidance at the earlier of an event-driven impairment test in 2017 or when we perform our annual goodwill impairment test in the fourth quarter of 2017. We cannot assess the impact on our financial statements because the determination will be made based on a fair value measurement at the time the test is conducted.

In May 2017, the FASB issued authoritative guidance to address diversity in practice and cost and complexity of applying the guidance in stock compensation to a change to the terms or conditions of a share-based payment award. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. We are currently evaluating the potential impact of the adoption on the consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

2. Changes in accumulated other comprehensive loss by component

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Foreign currency translation				
Balance at beginning of period	$ (146.3)	$ (120.7)	$ (148.3)	$ (139.1)
Other comprehensive loss:				
Foreign currency translation adjustments(1)	4.7	1.0	6.7	19.4
Balance at end of period	$ (141.6)	$ (119.7)	$ (141.6)	$ (119.7)
Pension				
Balance at beginning of period	$ (0.8)	$ (0.4)	$ (0.9)	$ (0.4)
Other comprehensive loss:				
Curtailment gain	—	—	0.1	—
Tax benefit (expense)	—	—	—	—
Total Other comprehensive (loss) income before reclassifications, net of tax	—	—	0.1	—
Total amount reclassified from accumulated other comprehensive loss, net of tax	—	—	—	—
Total other comprehensive income	—	—	0.1	—
Balance at end of period	$ (0.8)	$ (0.4)	$ (0.8)	$ (0.4)
Cash flow hedges				
Balance at beginning of period	$ 0.8	$ (0.1)	$ 0.7	$ 0.2
Other comprehensive loss:				
Net change from periodic revaluations	(0.2)	(0.3)	(0.5)	(1.1)
Tax benefit	0.1	0.1	0.2	0.4

Total Other comprehensive loss before reclassifications, net of tax	(0.1)	(0.2)	(0.3)	(0.7)
Net amount reclassified to earnings:				
Interest rate swaps(2)	0.2	0.3	0.7	0.6
Tax expense	(0.1)	(0.1)	(0.3)	(0.2)
Total amount reclassified from accumulated other comprehensive loss, net of tax	0.1	0.2	0.4	0.4
Total other comprehensive income (loss)	—	—	0.1	(0.3)
Balance at end of period	$ 0.8	$ (0.1)	$ 0.8	$ (0.1)

(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 U.S. dollars, except per share amounts)

(Unaudited)

3. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three and six months ended June 30, 2017 and 2016, respectively, for our proportional ownership interest in equity method investments:

	Three Months Ended June 30,		Six Months Ended June 30,	
Operating results	2017	2016	2017	2016
Revenue				
Frederickson	$ 4.8	$ 4.8	$ 10.1	$ 9.9
Orlando Cogen, LP	12.9	13.2	26.1	26.7
Koma Kulshan Associates	0.8	0.8	1.1	1.2
Chambers Cogen, LP	10.3	10.4	22.6	23.1
Selkirk Cogen Partners, LP	1.0	1.4	1.8	2.8
	29.8	30.6	61.7	63.7
Project expenses				
Frederickson	7.5	4.9	11.9	9.4
Orlando Cogen, LP	7.8	6.0	14.9	12.6
Koma Kulshan Associates	0.3	0.2	0.6	0.6
Chambers Cogen, LP	9.2	9.7	18.3	18.5
Selkirk Cogen Partners, LP	1.3	1.7	2.8	3.4
	26.1	22.5	48.5	44.5
Project other expense				
Frederickson	—	—	—	—
Orlando Cogen, LP	—	—	—	—
Koma Kulshan Associates	—	—	—	—

Chambers Cogen, LP	(47.5)	(0.5)	(48.0)	(0.9)
Selkirk Cogen Partners, LP	(10.6)	—	(10.6)	—
	(58.1)	(0.5)	(58.6)	(0.9)
Project income (loss)				
Frederickson	(2.7)	(0.1)	(1.8)	0.5
Orlando Cogen, LP	5.1	7.2	11.2	14.1
Koma Kulshan Associates	0.5	0.6	0.5	0.6
Chambers Cogen, LP	(46.4)	0.2	(43.7)	3.7
Selkirk Cogen Partners, LP	(10.9)	(0.3)	(11.6)	(0.6)
Equity in (loss) earnings of unconsolidated affiliates	$ (54.4)	$ 7.6	$ (45.4)	$ 18.3
Distributions from equity method investments	(13.5)	(19.2)	(17.2)	(23.5)
Deficit in earnings of equity method investments, net of distributions	$ (67.9)	$ (11.6)	$ (62.6)	$ (5.2)

We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long term investments. Therefore, we complete our assessments with a long term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

In the second quarter of 2017, we performed impairment tests at our Chambers and Selkirk projects, which are accounted for under the equity method of accounting.

Selkirk

We own a 17.7% limited partner interest in Selkirk Cogen Partners, L.P. The project has operated as a merchant facility since the expiration of its PPA in August 2014. Since the expiration of its PPA, we have not received a distribution from Selkirk and have recorded a cumulative $1.2 million project loss. Based on the project's history of providing no cash distributions while operating as a merchant facility, the short-term and long-term operational forecast, as well as the likelihood that further investment will be required in order to operate the facility, we determined that our investment in Selkirk is impaired and the decline in value is other than temporary. Accordingly, we recorded a $10.6 million full impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017.

Chambers

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. The Chambers project operates under a PPA that expires in March 2024. Prior to our impairment analysis, Chambers was recorded as a $124 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets. We have recorded equity earnings of $3.4 million, $5.5 million and $6.5 million for the six months ended June 30, 2017, year ended December 31, 2016 and year ended December 31, 2015, respectively. During those periods, we also received cumulative distributions of $33.6 million from Chambers.

During the second quarter of 2017, we performed an analysis of the post-PPA value of Chambers operating as a merchant facility. While declining power prices have been observed over the past several years, in our most recent long-term forecast, we identified a significant decrease in the long-term outlook for power prices in the region where Chambers operates. These forward prices, which were obtained from a third party, including forward prices of gas and coal, had a significant negative impact on the estimated discounted cash flows ("DCFs") of Chambers post-PPA. The estimated post-PPA value is a significant component of the project's overall value when compared to its carrying value of $124 million.

When determining if this decrease in value is other than temporary, we considered the likelihood that future conditions would change such that the gas and coal prices currently observed in the forward pricing models would become more favorable over time in order for the plant to be profitable in a merchant market. We also engaged a separate third party to provide its outlook on post-PPA value for Chambers. It is our assessment that gas prices are likely to remain low when considering the current and expected future supply of shale gas. The third party provided similar conclusions to our assessment.

Based on these factors, we determined that the decline in the fair value of our equity investment in Chambers is other than temporary. We recorded a $47.1 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017. After recording the impairment, our equity investment in Chambers is $77.2 million, which represents its estimated fair value at June 30, 2017.

We determine the fair value of our equity investments using an income approach with DCF models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount

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rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The discounted cash flows utilized in our impairment tests are generally based on approved operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular investment and is based upon an assumed capital structure, cost of long term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of an equity method investment.

The valuation of equity method investments is considered a level 3 fair value measurement, which means that the valuation of the investments reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the investments. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of an equity investment impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our investments may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts.

4. Long term debt

Long term debt consists of the following:

	June 30, 2017	December 31, 2016	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2023(1)	$ 587.7	$ 639.9	LIBOR(2) plus 4.25 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	161.8	156.4	5.95 %
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	10.4	13.5	LIBOR plus 3.130 %
Cadillac term loan, due 2025	25.5	27.0	LIBOR plus 1.37 %
Piedmont term loan, due 2018	56.6	56.6	LIBOR plus 3.75 %
Other long-term debt	0.2	0.2	5.50 % - 6.70 %
Less: unamortized discount	(14.9)	(17.2)	
Less: unamortized deferred financing costs	(12.8)	(15.3)	
Less: current maturities	(106.9)	(111.9)	
Total long-term debt	$ 707.6	$ 749.2	

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Current maturities consist of the following:

	June 30, 2017	December 31, 2016	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2023(1)	$ 95.0	$ 100.0	LIBOR(2) plus 4.25 %
Epsilon Power Partners term facility, due 2019	6.3	6.2	LIBOR plus 3.130 %
Cadillac term loan, due 2025	3.0	3.0	LIBOR plus 1.37 %
Piedmont term loan, due 2018	2.5	2.5	LIBOR plus 3.75 %
Other short-term debt	0.1	0.2	5.50 % - 6.70 %
Total current maturities	$ 106.9	$ 111.9	

(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) LIBOR cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $375.7 million of the $587.7 million outstanding aggregate borrowings under our senior secured term loan facility at June 30, 2017. See Note 6, Accounting for derivative instruments and hedging activities for further details. On April 17, 2017, the repricing of the $615 million senior secured term loan and $200 million senior secured revolving credit facility became effective. As a result of the repricing, the interest rate margin on the term loan and revolver was reduced by 0.75% to LIBOR plus 4.25%.

5. 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 of June 30, 2017 and December 31, 2016. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 104.4	$ —	$ —	$ 104.4
Restricted cash	14.1	—	—	14.1
Derivative instruments asset	—	5.6	—	5.6
Total	$ 118.5	$ 5.6	$ —	$ 124.1
Liabilities:				
Derivative instruments liability	$ —	$ 30.7	$ —	$ 30.7
Total	$ —	$ 30.7	$ —	$ 30.7

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	December 31, 2016			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 85.6	$ —	$ —	$ 85.6
Restricted cash	13.3	—	—	13.3
Derivative instruments asset	—	8.6	—	8.6
Total	$ 98.9	$ 8.6	$ —	$ 107.5
Liabilities:				
Derivative instruments liability	$ —	$ 28.9	$ —	$ 28.9
Total	$ —	$ 28.9	$ —	$ 28.9

The fair values of our derivative instruments 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 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 June 30, 2017, the credit valuation adjustments resulted in a $4.2 million net increase in fair value, which consists of a $0.3 million pre tax gain in other comprehensive income and a $3.9 million gain in change in fair value of derivative instruments. As of December 31, 2016, the credit valuation adjustments resulted in a $3.8 million net increase in fair value, which consists of a $0.3 million pre tax gain in other comprehensive income and a $3.5 million gain in change in fair value of derivative instruments.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature.

6. 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 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 entered into various gas purchase and sale agreements for our Nipigon projects that expire ranging from October 31, 2018 through December 31, 2022. In June 2014, Atlantic Power Limited Partnership (“APLP”) entered into contracts for the purchase of 2.9 million Gigajoules (“Gj”) of future natural gas purchases beginning on November 1, 2014 and expiring on December 31, 2017 for our projects in Ontario. In December 2016, we also entered into a gas purchase agreement for our Kenilworth project to fix the price of 0.8 million Mmbtu of natural purchases beginning on January 1, 2017 and expiring on December 31, 2017. These agreements do not qualify for the normal purchase normal sales (“NPNS”) exemption and are accounted for as derivative financial instruments because we could not conclude that it is probable that these contracts will not settle net and will result in physical delivery. These derivative financial instruments 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 also entered into various natural gas sales and purchase agreements for approximately 120,000 Mmbtu to effectively mitigate seasonal fluctuation of future natural gas price at Morris through January 2018. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at June 30, 2017. Changes in the fair market value of these contracts are 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 3.7 million Mmbtu of future natural gas purchases at Orlando, which is approximately 90% of our share of the expected natural gas purchases at the project through December 2018. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at June 30, 2017. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

In July 2017, we also entered into natural gas swaps to effectively fix the price of 6.2 million Mmbtu of future natural gas purchases through December 2020. This is approximately 90% of our share of the expected natural gas purchases at the project through December 2019 and approximately 50% of our share of the expected natural gas purchases through December 2020.

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 for $375.7 million notional amount of the remaining $587.7 million aggregate principal amount of borrowings under the senior secured term loans. These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the senior secured term loans bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 4.25%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 5.25% all-in rate on the senior secured term loans. As a result of entering into the swap agreements, the all-in rate for $375.7 million of the senior secured term loans cannot be less than 5.25%, if the Adjusted Eurodollar Rate is equal to or greater than 1.00%.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable rate debt. The interest rate swap agreements effectively convert the floating rate debt from LIBOR plus an applicable margin of 3.75% to a fixed rate of 4.47% plus an applicable margin of 4.00% until the maturity of the debt in August 2018, resulting in an all in rate of 8.47%. The swap continues at the fixed rate of 4.47% until November 2030. The interest rate swaps expire on November 30, 2030. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

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 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. Principal and interest payments for our senior secured term loans as well as our U.S dollar-denominated convertible debentures 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. In March 2017, we entered into foreign exchange forward contracts to sell Cdn$10 million at an exchange rate of 1.3381 on each of June 19, 2017, September 19, 2017 and December 19, 2017. On June 19, 2017, the first Cdn$10 million forward contract settled. The 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 at June 30, 2017.

In July 2017, we entered into additional foreign exchange forward contracts to sell total of Cdn$10 million at an exchange rate of 1.2943 on each of March 20, 2018, June 20, 2018 and December 20, 2018 and to sell total of Cdn$3.3 million at exchange rate of 1.2481 on each of March 19, 2018, June 19, 2018 and December 19, 2018.

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 the normal purchase normal sales (“NPNS”) exemption at June 30, 2017 and December 31, 2016:

	Units	June 30, 2017	December 31, 2016
Natural gas swaps	Natural Gas (Mmbtu)	6.0	4.9
Gas purchase agreements	Natural Gas (Gigajoules)	11.5	11.3
Interest rate swaps	Interest (US$)	458.4	506.9
Foreign currency forward contracts	Dollars (Cdn$)	20.0	-

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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:

	June 30, 2017	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.7
Interest rate swaps long-term	—	1.8
Total derivative instruments designated as cash flow hedges	—	2.5
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	1.2	1.5
Interest rate swaps long-term	2.8	6.4
Natural gas swaps current	1.6	1.0
Natural gas swaps long-term	—	0.3
Gas purchase agreements current	—	2.6
Gas purchase agreements long-term	—	15.9
Foreign currency forward contracts current	—	0.5
Total derivative instruments not designated as cash flow hedges	5.6	28.2
Total derivative instruments	$ 5.6	$ 30.7

	December 31, 2016	
	Derivative	Derivative

	Assets	Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.8
Interest rate swaps long-term	—	2.0
Total derivative instruments designated as cash flow hedges	—	2.8
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	0.4	1.9
Interest rate swaps long-term	4.5	6.5
Natural gas swaps current	3.9	0.8
Natural gas swaps long-term	0.1	—
Gas purchase agreements current	—	4.5
Gas purchase agreements long-term	—	12.7
Total derivative instruments not designated as cash flow hedges	8.9	26.4
Total derivative instruments	$ 8.9	$ 29.2

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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 June 30, 2017	Interest Rate Swaps
Accumulated OCI balance at March 31, 2017	$ 0.8
Change in fair value of cash flow hedges	(0.1)
Realized from OCI during the period	0.1
Accumulated OCI balance at June 30, 2017	$ 0.8

Three Months Ended June 30, 2016	Interest Rate Swaps
Accumulated OCI balance at March 31, 2016	$ (0.1)
Change in fair value of cash flow hedges	(0.2)
Realized from OCI during the period	0.2
Accumulated OCI balance at June 30, 2016	$ (0.1)

Six Months Ended June 30, 2017	Interest Rate Swaps
Accumulated OCI balance at January 1, 2017	$ 0.7
Change in fair value of cash flow hedges	(0.3)
Realized from OCI during the period	0.4
Accumulated OCI balance at June 30, 2017	$ 0.8

Six Months Ended June 30, 2016	Interest Rate Swaps
Accumulated OCI balance at January 1, 2016	$ 0.2
Change in fair value of cash flow hedges	(0.7)
Realized from OCI during the period	0.4
Accumulated OCI balance at June 30, 2016	$ (0.1)

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 June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Gas purchase agreements	Fuel	$ 2.4	$ 12.5	4.9	$ 24.0
Natural gas swaps	Fuel	(0.4)	1.3	(0.5)	3.3
Interest rate swaps	Interest, net	0.8	1.1	1.7	1.7

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

	Classification of gain (loss) recognized in income	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Natural gas swaps	Change in fair value of derivatives	$ (0.8)	$ 4.0	$ (0.6)	$ 5.8
Gas purchase agreements	Change in fair value of derivatives	(0.8)	11.4	(2.9)	11.2
Interest rate swaps	Change in fair value of derivatives	(1.1)	(3.2)	(0.4)	(6.0)
		$ (2.7)	$ 12.2	$ (3.9)	$ 11.0
Foreign currency forwards	Foreign exchange loss	$ (0.3)	$ —	$ (0.5)	$ —

7. Income taxes

	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016

Current income tax expense	$ 1.4	$ 0.3	$ 2.3	$ 1.8
Deferred income benefit	(23.7)	(18.7)	(24.9)	(18.6)
Total income tax benefit, net	$ (22.3)	$ (18.4)	$ (22.6)	$ (16.8)

For the three and six months ended June 30, 2017 and 2016

Income tax benefit for the three months ended June 30, 2017 was $22.3 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $11.0 million. The primary items impacting the tax rate for the three months ended June 30, 2017 were $0.2 million relating to return to provision adjustments. These items were offset by $8.4 million relating to operating in higher tax rate jurisdictions, $2.6 million related to a net decrease to the Company's valuation allowances in Canada due to income and $0.6 million relating to foreign exchange.

Income tax benefit for the three months ended June 30, 2016 was $18.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $9.0 million. The primary items impacting the tax rate for the three months ended June 30, 2016 were $4.6 million related to capital gain on intercompany notes, $2.6 million related to foreign exchange, $1.8 million relating to a change in the valuation allowance and $0.4 million of other permanent differences. These items were offset by $18.8 million related to capital loss recognized on tax restructuring.

Income tax benefit for the six months ended June 30, 2017 was $22.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $11.2 million. The primary items impacting the tax rate for the six months ended June 30, 2017 were $0.3 million relating to return to provision adjustments. These items were offset by $8.7 million relating to operating in higher tax rate jurisdictions, $1.9 million related to a net decrease to the Company's valuation allowances in Canada due to income, $1.0 million relating to foreign exchange and $0.1 million of other permanent differences.

Income tax benefit for the six months ended June 30, 2016 was $16.8 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.0 million. The primary items impacting the tax rate for the six months ended June 30, 2016 were $5.1 million relating to foreign exchange, $4.6 million relating to a change in the valuation allowance, $4.2 million related to capital gain on intercompany notes and $0.1 million of other permanent differences. These items were offset by $18.8 million related to capital loss recognized on tax restructuring.

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As of June 30, 2017, we have recorded a valuation allowance of $184.1 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 future taxable income in the United States and in Canada and available tax planning strategies.

8. Equity compensation plans

Long term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2017:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2016	2,101,118	2.08
Granted	1,817,463	2.38
Vested and redeemed	(973,091)	2.22

Forfeitures	(24,226)		2.32
Outstanding at June 30, 2017	2,921,264	$	2.22

Transition Equity Participation Agreement

We also have 539,904 transition notional shares outstanding at June 30, 2017 under the Transition Equity Participation Agreement with James J. Moore, Jr. Fifty percent of the transition notional shares granted with respect to fiscal year 2015 will vest upon the four-year anniversary of the date of grant and the remaining portion 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).

Cash payments made for vested notional units for the six months ended June 30, 2017 and 2016 were $0.7 million and $0.4 million, respectively. Compensation expense for LTIP and Transition Equity Participation Agreement notional shares was $0.9 million and $1.7 million for the three and six months ended June 30, 2017 and $0.8 million and $0.9 million for the three and six months ended June 30, 2016, respectively.

9. Basic and diluted loss per share

Basic loss per share is calculated by dividing net loss by the weighted average common shares outstanding during their respective period. Diluted loss per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the three and six months ended June 30, 2017 and 2016, respectively, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

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The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Numerator:				
Net loss attributable to Atlantic Power Corporation	$ (21.9)	$ (18.5)	$ (24.6)	$ (33.5)
Denominator:				
Weighted average basic shares outstanding	115.2	121.6	115.0	121.8
Dilutive potential shares:				
Convertible debentures	8.1	14.8	8.1	18.3
LTIP notional units	—	0.1	—	0.1
Potentially dilutive shares	123.3	136.5	123.1	140.2
Basic and diluted loss per share attributable to Atlantic Power Corporation	$ (0.19)	$ (0.15)	$ (0.21)	$ (0.28)

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 EPS 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. Potentially dilutive shares from convertible debentures of $8.1 million and $8.1 million have been excluded from fully diluted shares in the three and six months ended June 30, 2017, respectively, because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures of $14.8 million and $18.3 million have been excluded from fully diluted shares in the three and six months ended June 30, 2016, respectively, because their impact would be anti-dilutive.

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10. 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 six months ended June 30, 2017 and 2016:

	Six months ended June 30, 2017		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity
Balance at January 1, 2017	$ 64.6	$ 221.3	$ 285.9
Net (loss) income	(24.6)	4.3	(20.3)
Realized and unrealized gain on hedging activities, net of tax	0.1	—	0.1
Foreign currency translation adjustment	6.7	—	6.7
Defined benefit plan, net of tax	0.1	—	0.1
Stock-based compensation	1.1	—	1.1
Dividends declared on preferred shares of a subsidiary company	—	(4.3)	(4.3)
Balance at June 30, 2017	$ 48.0	$ 221.3	$ 269.3

	Six months ended June 30, 2016	
	Total Atlantic	Preferred shares issued by a subsidiary

	Power Corporation Shareholders' Equity	company	Total Equity
Balance at January 1, 2016	$ 213.9	$ 221.3	$ 435.2
Net (loss) income	(33.5)	4.2	(29.3)
Realized and unrealized loss on hedging activities, net of tax	(0.3)	—	(0.3)
Foreign currency translation adjustment	19.4	—	19.4
Common share repurchases	(4.7)	—	(4.7)
Stock-based compensation	0.8	—	0.8
Dividends declared on preferred shares of a subsidiary company	—	(4.2)	(4.2)
Balance at June 30, 2016	$ 195.6	$ 221.3	$ 416.9

Stock Repurchase Program

In December 2015, our Board of Directors approved an NCIB for each series of our convertible unsecured subordinated debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd ("APPEL"), our wholly-owned subsidiary. The Board authorization permitted the Company to repurchase stock through open market repurchases. The NCIB expired on December 28, 2016. Through June 30, 2016, we repurchased and cancelled 2.0 million common shares at a total cost of $4.7 million. For the year ended December 31, 2016, we repurchased a cumulative 8.0 million common shares at a total cost of $19.5 million. Repurchases and retirement of common shares are recorded to common shares on the consolidated balance sheets.

On December 29, 2016, we commenced a new NCIB that will expire on December 28, 2017 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIBs. Under the new NCIB, we may purchase up to approximately 11.3 million common shares, or 10% of our public float. We did not repurchase any

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common shares in the six months ended June 30, 2017. In July 2017, we repurchased and cancelled 171,612 of our 4.85% Cumulative Redeemable Preferred Shares at Cdn$15.5 per share for a total payment of Cdn$2.7 million.

11. 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 (loss) 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 (loss).

A reconciliation of Project Adjusted EBITDA to net loss for the three months ended June 30, 2017 and 2016 is included in the table below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended June 30, 2017					
Project revenues	$ 40.4	$ 27.9	$ 55.4	$ 0.3	$ 124.0
Segment assets	688.5	299.3	281.9	104.4	1,374.1
Project Adjusted EBITDA	$ 29.1	$ 10.6	$ 45.2	$ 0.5	$ 85.4
Change in fair value of derivative instruments	0.7	—	0.9	1.0	2.6
Depreciation and amortization	11.4	10.0	13.2	0.1	34.7
Interest, net	2.6	(0.1)	—	—	2.5
Impairment	57.7	—	—	—	57.7
Project (loss) income	(43.3)	0.7	31.1	(0.6)	(12.1)
Administration	—	—	—	5.7	5.7
Interest expense, net	—	—	—	18.4	18.4
Foreign exchange loss	—	—	—	5.9	5.9
(Loss) income from continuing operations before income taxes	(43.3)	0.7	31.1	(30.6)	(42.1)
Income tax benefit	—	—	—	(22.3)	(22.3)
Net (loss) income from continuing operations	$ (43.3)	$ 0.7	$ 31.1	$ (8.3)	$ (19.8)

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	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended June 30, 2016					
Project revenues	$ 33.7	$ 25.5	$ 38.8	$ 0.2	$ 98.2
Segment assets	775.7	335.9	430.3	168.0	1,709.9
Project Adjusted EBITDA	$ 20.9	$ 14.5	$ 10.9	$ (0.1)	$ 46.2
Change in fair value of derivative instruments	(2.5)	—	(11.6)	1.9	(12.2)
Depreciation and amortization	10.9	9.9	9.6	—	30.4
Interest, net	2.9	—	—	—	2.9
Other project expense	—	—	—	(0.1)	(0.1)
Project income (loss)	9.6	4.6	12.9	(1.9)	25.2
Administration	—	—	—	5.8	5.8
Interest expense, net	—	—	—	51.2	51.2
Foreign exchange loss	—	—	—	2.6	2.6
Other income, net	—	—	—	0.3	0.3
Income (loss) from continuing operations before income taxes	9.6	4.6	12.9	(61.8)	(34.7)
Income tax benefit	—	—	—	(18.4)	(18.4)
Net income (loss) from continuing operations	$ 9.6	$ 4.6	$ 12.9	$ (43.4)	$ (16.3)

Un-Allocated

	East U.S.	West U.S.	Canada	Corporate	Consolidated
Six Months Ended June 30, 2017					
Project revenues	$ 76.5	$ 51.3	$ 94.1	$ 0.5	$ 222.4
Segment assets	688.5	299.3	281.9	104.4	1,374.1
Project Adjusted EBITDA	$ 56.2	$ 19.8	$ 72.8	$ 0.5	$ 149.3
Change in fair value of derivative instruments	1.3	—	4.1	(1.6)	3.8
Depreciation and amortization	22.7	19.8	26.4	0.4	69.3
Interest, net	5.3	—	—	—	5.3
Impairment	57.7	—	—	—	57.7
Project (loss) income	(30.8)	—	42.3	1.7	13.2
Administration	—	—	—	12.1	12.1
Interest expense, net	—	—	—	35.7	35.7
Foreign exchange loss	—	—	—	8.3	8.3
(Loss) income from continuing operations before income taxes	(30.8)	—	42.3	(54.4)	(42.9)
Income tax benefit	—	—	—	(22.6)	(22.6)
Net (loss) income from continuing operations	$ (30.8)	$ —	$ 42.3	$ (31.8)	$ (20.3)

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	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Six Months Ended June 30, 2016					
Project revenues	$ 73.1	$ 44.5	$ 86.5	$ 0.5	$ 204.6
Segment assets	775.7	335.9	430.3	168.0	1,709.9
Project Adjusted EBITDA	$ 51.2	$ 22.0	$ 35.7	$ (0.2)	$ 108.7
Change in fair value of derivative instruments	(1.7)	—	(12.1)	2.8	(11.0)
Depreciation and amortization	21.9	19.7	18.5	0.2	60.3
Interest, net	5.4	—	—	—	5.4
Other project expense	—		—	0.1	0.1
Project income (loss)	25.6	2.3	29.3	(3.3)	53.9
Administration	—	—	—	11.9	11.9
Interest expense, net	—	—	—	67.8	67.8
Foreign exchange loss	—	—	—	22.5	22.5
Other income, net	—	—	—	(2.2)	(2.2)
Income (loss) from continuing operations before income taxes	25.6	2.3	29.3	(103.3)	$ (46.1)
Income tax benefit	—	—	—	(16.8)	(16.8)
Net income (loss) from continuing operations	$ 25.6	$ 2.3	$ 29.3	$ (86.5)	$ (29.3)

The table below provides information, by country, about our consolidated operations for each of the three and six months ended June 30, 2017 and 2016 and Property, Plant & Equipment as of June 30, 2017 and December 31, 2016, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Project Revenue Three Months Ended June 30,		Project Revenue Six Months Ended June 30,		Property, Plant and Equipment, net of accumulated depreciation	
	2017	2016	2017	2016	June 30, 2017	December 31, 2016
United States	$ 68.6	$ 59.4	$ 128.3	$ 118.1	$ 486.7	$ 499.2
Canada	55.4	38.8	94.1	86.5	219.1	234.0
Total	$ 124.0	$ 98.2	$ 222.4	$ 204.6	$ 705.8	$ 733.2

Independent Electricity System Operator (“IESO”), Ontario Electricity Financial Corporation (“OEFC”) and Niagara Mohawk provided 17.8%, 17.8% and 11.8%, respectively, of total consolidated revenues for the three months ended June 30, 2017. IESO, Niagara Mohawk and OEFC provided 20.9%, 12.1% and 11.5%, respectively, of total consolidated revenues for the six months ended June 30, 2017. IESO, BC Hydro and San Diego Gas & Electric provided 31.3%, 14.0% and 11.1%, respectively, of total consolidated revenues for the three months ended June 30, 2016. IESO, BC Hydro and Niagara Mohawk provided 34.8%, 14.1% and 8.7%, respectively, of total consolidated revenues for the six months ended June 30, 2016. IESO and OEFC purchase electricity from the Calstock, Kapuskasing, Nipigon and North Bay projects in the Canada segment, San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West U.S. segment, Niagara Mohawk purchases electricity from the Curtis Palmer 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.

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(Unaudited)

12. 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

Ontario Electricity Financial Corporation (“OEFC”) Settlement

On January 19, 2017, the Supreme Court of Canada denied the Ontario Electricity Financial Corporation (“OEFC”) leave to appeal the Ontario Court of Appeal Decision concerning the interpretation of the price escalator for power sold to the OEFC under certain power purchase agreements with non-utility generators. We were not party to that litigation. We did, however, enter into a standstill agreement with the OEFC in April 2015, with respect to our North Bay, Kapuskasing and Tunis projects, arising out of our disagreement with the OEFC over the interpretation of the price escalator calculation in our PPAs. Under the standstill agreement we reserved our right to bring claims against the OEFC and suspended the running of any applicable limitation period to bring such claims.

On April 27, 2017, we entered into a settlement agreement with the OEFC with respect to our standstill agreement. Under the terms of the settlement, the OEFC has agreed to pay us approximately Cdn$36.4 million, representing the application of the price escalator calculation under the respective PPAs for power sold to the OEFC beginning in April 2013 and through December 31, 2017.

Of the Cdn$36.4 million amount agreed upon in settlement, we have received Cdn$32.8 million (approximately $24.7 million) and recorded it as revenue in the three and six months ended June 30, 2017, the period when all contingencies have been resolved. The remaining Cdn $3.6 million of the settlement relates to the application of the price escalator to the enhanced dispatch contracts at North Bay and Kapuskasing and will be recognized as revenue, when earned, through the expiration date of December 31, 2017.

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 June 30, 2017.

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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;

· 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, 2016 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, 2016 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;

- 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 or long lived assets;
- 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 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

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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 owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long term PPAs, which seek to minimize exposure to changes in commodity prices. As of June 30, 2017, our power generation projects had an aggregate gross electric generation capacity of approximately 2,138 MW in which our aggregate ownership interest is approximately 1,500 MW. Our current portfolio consists of interests in twenty-three power generation projects across nine states in the United States and two provinces in Canada. Nineteen of the projects are currently operational, totaling 1,975 MW on a gross capacity basis and 1,337 MW on a net ownership basis. The remaining four projects, all in Ontario, are not operational, three due to revised contractual arrangements with the offtaker and the other, Tunis, has a forward-starting 15-year contractual agreement that will commence between November 2017 and June 2019. Eighteen of our projects are majority owned.

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 December 31, 2017 to December 31, 2037. Nine of our projects, representing 25% of our net MW and 30% of our 2016 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Kapuskasing (2017), North Bay (2017), Williams Lake (2018), Kenilworth (2018), Naval Station (2019), Naval Training Center (2019), North Island (2019), Calstock (2020) and Oxnard (2020). There are no PPA expirations in 2021. When a PPA expires, 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. Our MW-weighted average remaining PPA life is approximately 7 years. 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.

The majority of our natural gas, coal and biomass power generation projects have long term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass through of fuel costs to our customers. In cases where there is no pass through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

We directly operate and maintain eighteen of our 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

San Diego Contracts

In July 2017, we entered into new seven-year Power Purchase Tolling Agreements ("PPTAs") for our 48 MW Naval Station project and our 38.6 MW North Island project. The agreements are with San Diego Gas & Electric Company ("SDG&E"), the existing power customer for both projects. The PPTAs are subject to certain significant conditions or

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approvals, as described below. If these conditions are met, delivery obligations under the PPTAs would commence as early as February 2018.

Naval Station, North Island and Naval Training Center ("NTC") sell power to SDG&E under Power Purchase Agreements that are scheduled to expire on December 1, 2019 (the "Existing PPAs"). In addition, all three projects sell steam to the U.S. Navy under agreements that are scheduled to expire in February 2018 (the "Navy agreements"). These agreements provide us with the right to use the property at the respective sites on which each project is located. Those rights will also expire in February 2018.

The Navy, which does not expect to have a need for steam from these projects after the existing agreements expire, initiated a solicitation in early March for proposals to provide energy security and resiliency using the existing sites for Naval Station and North Island. In late May, we submitted detailed proposals for both sites in the second phase of the three-phase solicitation. If successful in this process, we would retain continued use of the two sites beyond February 2018 ("site control").

The new PPTAs are subject to certain significant conditions, including obtaining the approval of the California Public Utilities Commission ("CPUC") and retaining site control. CPUC approval could take approximately four months or longer. The timeframe for the Navy process is undetermined.

We have executed amendments to the Existing PPAs with SDG&E for Naval Station, North Island and Naval Training Center, which provide for termination of the Existing PPAs as early as February 2018, coincident with the expiration of the Navy agreements. These amendments to the Existing PPAs are also subject to CPUC approval.

We have also entered into Resource Adequacy ("RA") contracts with SDG&E for all three projects, which are subject to CPUC approval and are conditioned upon retaining site control beyond February 2018. The RA contracts for Naval Station and North Island are contingent arrangements that would become effective only under limited circumstances and conditions. In addition, we and SDG&E have entered into an RA contract for NTC, under which NTC would supply RA capacity to SDG&E from February through December 2018. The NTC project is not included in the Navy's solicitation for the other two sites and thus the process for retaining control of the NTC site is undertermined.

We expect approximately $16 million of Project Adjusted EBITDA from Naval Station and North Island on a combined basis for 2017. Power prices and interest rates are significantly lower now than at the time the Existing PPAs were originally executed in the mid-1980s. In addition, the incremental investment required to meet the requirements of the PPTAs is much less than the original investment. For these reasons, the Project Adjusted EBITDA of the two projects under the PPTAs is expected to be approximately $6 million annually on a combined basis, beginning in February 2018. In conjunction with the new PPTAs, we expect to make investments in both projects in the form of major maintenance and upgrades, primarily in 2018.

The NTC project, which has a capacity of 25 MW, is expected to generate approximately $4 million of Project Adjusted EBITDA in 2017. We are continuing to pursue contractual arrangements for the project following the early termination of its PPA. If successful, the resulting Project Adjusted EBITDA is expected to be significantly lower than the 2017 level.

Impairment of Equity Method Investments

Selkirk

We own a 17.7% limited partner interest in Selkirk Cogen Partners, L.P. The project has operated as a merchant facility since the expiration of its PPA in August 2014. Since the expiration of its PPA, we have not received a distribution from Selkirk and have recorded a cumulative $1.2 million project loss. Based on the project’s history of providing no cash distributions while operating as a merchant facility, the short-term and long-term operational forecast, as well as the likelihood that further investment will be required in order to operate the facility, we determined that our investment in Selkirk is impaired and the decline in value is other than temporary. Accordingly, we recorded a $10.6 million full impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017.

Chambers

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. Chambers operates under a PPA that expires in March 2024. During the second quarter of 2017, we performed an analysis of the post-PPA

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value of Chambers operating as a merchant facility. While declining power prices have been observed over the past several years, we identified a significant decrease in the long-term outlook for power prices in the region where Chambers operates in our most recent long-term forecast. These forward prices obtained from a third party, including the price of gas and coal, had a significant negative impact on the estimated discounted cash flows of Chambers. The estimated post-PPA value is a significant component of the project's overall value when compared to its carrying value of $124 million.

When determining if this decrease in value is other than temporary, we considered the likelihood that future conditions would change such that the gas and coal prices currently observed in the forward pricing models would become more favorable over time in order for the plant to be profitable in a merchant market. It is our assessment that gas prices are likely to remain low when considering the current and expected future supply of shale gas. Based on these factors, we determined that the decline in the fair value of our equity investment in Chambers was other than temporary. We recorded a $47.1 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017. After recording the impairment, our equity investment in Chambers is $77.2 million, which represents its estimated fair value at June 30, 2017.

OEFC Settlement

On April 27, 2017, we entered into a settlement agreement with the OEFC relating to a standstill agreement we entered into with the OEFC in April 2015, with respect to our North Bay, Kapuskasing and Tunis projects, arising out of our disagreement with the OEFC over the interpretation of the price escalator calculation in our PPAs. As a result of the settlement, the OEFC has agreed to pay us approximately Cdn$36.4 million, representing the application of the price escalator calculation under their respective PPAs for power sold to the OEFC beginning in April 2013 and through December 31, 2017.

Of the Cdn$36.4 million amount agreed upon in settlement, we have received Cdn$32.8 million (approximately $24.7 million) and recorded it as revenue in the three and six months ended June 30, 2017, the period when all contingencies have been resolved. The remaining Cdn$3.6 million of the settlement relates to the application of the price escalator to the enhanced dispatch contracts at North Bay and Kapuskasing and will be recognized as revenue, when earned, through the expiration date of December 31, 2017.

Senior secured term loan facility repricing

On April 17, 2017, the repricing of the $615 million senior secured term loan and $200 million senior secured revolving credit facility became effective. As a result of the repricing, the interest rate margin on the term loan and revolver was reduced by 0.75% to LIBOR plus 4.25%. The LIBOR floor remains at 1.00% and the mandatory 1% annual amortization and cash sweep provisions of the term loan are unchanged.

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OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of August 1, 2017, 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 ratings 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 (S
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	Illinois	Natural Gas	177	100.00%	120	Merchant	N/A	
					57	Equistar Chemicals, LP(2)	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(3)	March, 2024	
					16	Chemours Co.	March, 2024	
Kenilworth	New Jersey	Natural Gas	29	100.00%	29	Merck & Co., Inc.	September, 2018	
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corporation	December, 2027 (4)	
Selkirk(1)	New York	Natural Gas	345	17.70 %	61	Merchant	N/A	
West U.S. Segment								
Naval Station	California		47	100.00%	47			

		Natural Gas				San Diego Gas & Electric	November, 2019 (5)
Naval Training Center	California	Natural Gas	25	100.00 %	25	San Diego Gas & Electric	November, 2019 (5)
North Island	California	Natural Gas	40	100.00 %	40	San Diego Gas & Electric	November, 2019 (5)
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	April, 2020
Manchief	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April, 2022 (6)
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(1)	Washington	Hydro	13	49.80 %	6	Puget Sound Energy	March, 2037
Canada Segment							
Mamquam	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	March, 2018
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June, 2020
Kapuskasing	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 (7)
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2022 (8)
North Bay	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 (7)
Tunis	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	(9)

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

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

(3) 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.

(4) 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 June 30, 2017, the facility has generated 7,173 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

(5) Our land use license agreements with the U.S. Navy expire on February 8, 2018. Our PPAs with San Diego Gas & Electric expire on December 1, 2019. See Recent Developments – San Diego Contracts for additional information on these PPAs.

(6) Public Service Company of Colorado has options to purchase the project in either May 2020 or May 2021.

(7) In December 2016, we entered into agreements to terminate our PPAs originally scheduled to expire on December 31, 2017 one year ahead of their expiration dates. Additionally, we entered into enhanced dispatch contracts with the IESO, which provide a fixed monthly payment to the plants until December 31, 2017. The contracts have no delivery obligations and allow us to retain operating flexibility. Based on our assessment of the Ontario power market, including the estimated impact on plant economics, we do not expect to operate the plants during the term of the enhanced dispatch contracts or subsequent to their expiration.

(8) In December 2016, we entered into an enhanced dispatch contract with IESO. The enhanced dispatch contract for Nipigon provides fixed monthly payments to that plant through October 31, 2018. During that period, the plant's PPA with the OEFC will be suspended. At the conclusion of that period, the arrangement will revert to the existing terms of the PPA, which is scheduled to expire in December 2022. We do not expect Nipigon to be operational through October 31, 2018.

(9) In December 2014, we entered into an agreement with the Ontario Power Authority and its successor, the IESO for the future operations of the Tunis facility. Subject to meeting certain technical requirements, Tunis will operate under a 15-year agreement with the IESO commencing between November 2017 and June 2019. The new agreement provides the Tunis project with a fixed monthly payment which escalates annually according to a pre-defined formula while allowing it to earn additional energy revenues for those periods during which it operates.

Consolidated Overview and Results of Operations

Performance highlights

The following table provides a summary of our consolidated results of operations for the three and six months ended June 30, 2017 and 2016, which are analyzed in greater detail below:

	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Project revenue	$ 124.0	$ 98.2	$ 222.4	$ 204.6
Project (loss) income	$ (12.1)	$ 25.2	$ 13.2	$ 53.9
Net loss attributable to Atlantic Power Corporation	$ (21.9)	$ (18.5)	$ (24.6)	$ (33.5)
Loss per share attributable to Atlantic Power Corporation—basic and diluted	$ (0.19)	$ (0.15)	$ (0.21)	$ (0.28)
Project Adjusted EBITDA(1)	$ 85.4	$ 46.2	$ 149.3	$ 108.7

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

Revenue increased by $25.8 million from $98.2 million in the three months ended June 30, 2016 to $124.0 million in the three months ended June 30, 2017. The primary drivers of the increase are as follows:

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· OEFC settlement – we recorded approximately $24.7 million of revenue at North Bay, Kapuskasing and Tunis related to our settlement agreement entered into with the OEFC in April 2017 arising out of our disagreement over the interpretation of the price escalator calculation in our PPAs at these projects; and

· Hydrological conditions – a $5.0 million increase in revenue from higher water flows at our hydro projects.

These increases in project revenue were partially offset by:

· Enhanced dispatch contracts – under the enhanced dispatch contracts with the IESO, we suspended operations at our Kapuskasing, North Bay and Nipigon projects, which resulted in approximately $6.5 million of lower revenue than the comparable 2016 period.

Consolidated project income decreased by $37.3 million from $25.2 million of project income in the three months ended June 30, 2016 to $12.1 million project loss in the three months ended June 30, 2017. The primary drivers of the decrease are as follows:

· Impairment of Chambers and Selkirk – we recorded $57.7 million of impairments at our Chambers and Selkirk projects, which are accounted under the equity method of accounting;

· Fuel swap and natural gas purchase agreements – the change in fair value of our derivative instruments decreased $14.9 million from the comparable 2016 period; and

· Depreciation and amortization – depreciation expense increased $4.0 million from the comparable 2016 period due to the acceleration of depreciation at North Bay and Kapuskasing through December 2017, the expected end of the plants' useful lives.

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

· Revenue – revenue increased $25.8 million as discussed above; and

· Fuel expense – fuel expense decreased $11.7 million from the comparable 2016 period primarily due to the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016. These projects are currently not in operation under the terms of their enhanced dispatch contracts.

Revenue increased by $17.8 million from $204.6 million in the six months ended June 30, 2016 to $222.4 million in the six months ended June 30, 2017. The primary drivers of the increase are as follows:

- OEFC settlement – we recorded approximately $24.7 million of revenue at North Bay, Kapuskasing and Tunis related to our settlement agreement entered into with the OEFC in April 2017 arising out of our disagreement over the interpretation of the price escalator calculation in our PPAs at these projects; and

- Hydrological conditions – a $3.4 million increase in revenue from higher water flows at our hydro projects.

These increases in project revenue were partially offset by:

- Enhanced dispatch contracts – under the enhanced dispatch contracts with the IESO, we suspended operations at our Kapuskasing, North Bay and Nipigon projects, which resulted in approximately $12.4 million of lower revenue than the comparable 2016 period.

Consolidated project income decreased by $40.7 million from $53.9 million of project income in the six months ended June 30, 2016 to $13.2 million of project income in the six months ended June 30, 2017. The primary drivers of the decrease are as follows:

- Impairment of Chambers and Selkirk – we recorded $57.7 million of impairments at our Chambers and Selkirk projects, which are accounted under the equity method of accounting;

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- Fuel swap and natural gas purchase agreements – the change in fair value of our derivative instruments decreased $14.9 million from the comparable 2016 period; and

- Depreciation and amortization – depreciation expense increased $8.0 million from the comparable 2016 period due to the acceleration of depreciation at North Bay and Kapuskasing through December 2017, the expected end of the plants' useful lives.

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

- Revenue – revenue increased $17.8 million as discussed above; and

- Fuel expense – fuel expense decreased $21.1 million from the comparable 2016 period primarily due to the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016. These projects are currently not in operation under the terms of their enhanced dispatch contracts.

A detailed discussion of project income (loss) by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 48.

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 (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

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Three months ended June 30, 2017 compared to the three months ended June 30, 2016

The following table provides our consolidated results of operations:

	Three months ended June 30,			
	2017	2016	$ change	% change
Project revenue:				
Energy sales	$ 40.0	$ 45.1	$ (5.1)	(11.3) %
Energy capacity revenue	28.3	37.3	(9.0)	(24.1) %
Other	55.7	15.8	39.9	252.5 %
	124.0	98.2	25.8	26.3 %
Project expenses:				
Fuel	24.0	35.1	(11.1)	(31.6) %
Operations and maintenance	23.3	30.0	(6.7)	(22.3) %
Depreciation and amortization	29.5	25.5	4.0	15.7 %
	76.8	90.6	(13.8)	(15.2) %
Project other expense:				
Change in fair value of derivative instruments	(2.7)	12.2	(14.9)	(122.1) %
Equity in (loss) earnings of unconsolidated affiliates	(54.4)	7.6	(62.0)	NM
Interest expense, net	(2.2)	(2.4)	0.2	NM
Other income, net	—	0.2	(0.2)	(100.0) %
	(59.3)	17.6	(76.9)	NM
Project (loss) income	(12.1)	25.2	(37.3)	(148.0) %
Administrative and other expenses:				
Administration	5.7	5.8	(0.1)	(1.7) %
Interest expense, net	18.4	51.2	(32.8)	(64.1) %
Foreign exchange loss	5.9	2.6	3.3	126.9 %
Other expense, net	—	0.3	(0.3)	100.0 %
	30.0	59.9	(29.9)	(49.9) %
Loss from operations before income taxes	(42.1)	(34.7)	(7.4)	21.3 %
Income tax benefit	(22.3)	(18.4)	(3.9)	100.0 %
Net loss	(19.8)	(16.3)	(3.5)	21.5 %
Net income attributable to Preferred share dividends of a subsidiary company	2.1	2.2	(0.1)	(4.5) %
Net loss attributable to Atlantic Power Corporation	$ (21.9)	$ (18.5)	$ (3.4)	18.4 %

The following tables provide our project income by segment:

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	Three months ended June 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 24.4	$ 7.8	$ 7.8	$ —	$ 40.0
Energy capacity revenue	12.4	13.3	2.6	—	28.3
Other	3.6	6.8	45.0	0.3	55.7
	40.4	27.9	55.4	0.3	124.0
Project expenses:					
Fuel	10.5	10.5	3.0	—	24.0
Operations and maintenance	9.2	7.2	7.2	(0.3)	23.3
Depreciation and amortization	8.9	7.3	13.2	0.1	29.5
	28.6	25.0	23.4	(0.2)	76.8
Project other income (expense):					
Change in fair value of derivative instruments	(0.7)	—	(0.9)	(1.1)	(2.7)
Equity in loss of unconsolidated affiliates	(52.2)	(2.2)	—	—	(54.4)
Interest expense, net	(2.2)	—	—	—	(2.2)
Other expense, net	—	—	—	—	—
	(55.1)	(2.2)	(0.9)	(1.1)	(59.3)
Project (loss) income	$ (43.3)	$ 0.7	$ 31.1	$ (0.6)	$ (12.1)

	Three months ended June 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 17.5	$ 7.6	$ 20.0	$ —	$ 45.1
Energy capacity revenue	13.0	13.3	11.0	—	37.3
Other	3.2	4.6	7.8	0.2	15.8
	33.7	25.5	38.8	0.2	98.2
Project expenses:					
Fuel	12.0	7.9	15.2	—	35.1
Operations and maintenance	10.9	6.2	12.7	0.2	30.0
Depreciation and amortization	8.5	7.3	9.6	0.1	25.5
	31.4	21.4	37.5	0.3	90.6
Project other income (expense):					
Change in fair value of derivative instruments	2.5	—	11.6	(1.9)	12.2
Equity in earnings of unconsolidated affiliates	7.1	0.5	—	—	7.6
Interest expense, net	(2.4)	—	—	—	(2.4)
Other expense, net	0.1	—	—	0.1	0.2

	7.3	0.5	11.6	(1.8)	17.6
Project income (loss)	$ 9.6	$ 4.6	$ 12.9	$ (1.9)	$ 25.2

East U.S.

Project income for the three months ended June 30, 2017 decreased $52.9 million from the comparable 2016 period primarily due to:

- decreased project income of $46.6 million and $10.6 million at Chambers and Selkirk, respectively, primarily due to impairments of $47.1 million and $10.6 million recorded in the three months ended June 30, 2017; and

- decreased project income of $4.9 million at Orlando primarily due to a $4.5 million decrease in the change in fair value of derivatives and a maintenance outage, partially offset by lower fuel expense from the settlement of favorable fuel swaps.

These decreases were partially offset by:

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· increased project income of $6.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period; and

· increased project income of $2.1 million at Piedmont primarily due to a positive $0.7 million increase in the change in fair value of interest rate swap agreements, as well as a maintenance outage in the comparable 2016 period.

West U.S.

Project income for the three months ended June 30, 2017 decreased $3.9 million from the comparable 2016 period primarily due to:

· decreased project income of $2.7 million at Frederickson primarily due to higher planned maintenance expense than the comparable 2016 period;

· decreased project income of $0.7 million at Naval Station, which underwent a maintenance outage in the three months ended June 30, 2017; and

· decreased project income of $0.6 million at North Island, which also underwent a maintenance outage in the three months ended June 30, 2017.

Canada

Project income for the three months ended June 30, 2017 increased $18.2 million from the comparable 2016 period primarily due to:

· increased project income of $21.3 million at Kapuskasing, North Bay and Tunis, primarily due to approximately $24.7 million of revenue recorded related to the OEFC settlement, $11.6 million of lower fuel expense due to the expiration of fuel purchase agreements in December 2016 as well as to the enhanced dispatch agreements, and $3.9 million of lower maintenance expense due to the plants not being operational under the enhanced dispatch contracts. These increases were partially offset by a negative $10.2 million change in the fair value of gas purchase agreements that expired in December 2016 and were accounted for as derivatives and $3.9 million of accelerated depreciation at North Bay and Kapuskasing in the three months ended June 30, 2017.

These increases were partially offset by:

- decreased project income of $1.8 million at Nipigon primarily due to a negative $2.4 million change in the fair value of gas purchase agreements that are accounted for as derivatives; and

- decreased project income of $1.7 million at Mamquam primarily due to a forced maintenance outage that occurred during the three months ended June 30, 2017.

Un allocated Corporate

Total project loss for the three months ended June 30, 2017 of $0.6 million decreased from a total project loss of $1.9 million in the comparable 2016 period primarily due to a $0.8 million increase in the fair value of fuel swaps and gas purchase agreements accounted for as derivatives.

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

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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 did not change materially from the 2016 comparable period.

Interest expense, net

Interest expense decreased $32.8 million from the comparable 2016 period primarily due to the write-off of $31.4 million of deferred financing costs related to the Senior Secured Credit Facilities and repurchase and cancellation of convertible debentures during the three months ended June 30, 2016, as well as lower outstanding debt balances at June 30, 2017.

Foreign exchange loss

Foreign exchange loss for the three months ended June 30, 2017 increased $3.3 million from the comparable 2016 period primarily due to a $3.1 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The closing U.S. dollar to Canadian dollar exchange rates were 1.30 and 1.29 at June 30, 2017 and 2016, respectively, a decrease of 2.4% during the three months ended June 30, 2017, as compared to a decrease of 0.5% in the comparable 2016 period. The average U.S. dollar to Canadian dollar exchange rates were 1.33 and 1.29 for the three months ended June 30, 2017 and 2016, respectively.

Other expense, net

Other expense, net decreased $0.3 million primarily due to a gain recorded on the purchase and cancellation of convertible debentures in the comparable 2016 period.

Income tax expense

Income tax benefit for the three months ended June 30, 2017 was $22.3 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $11.0 million. The primary items impacting the tax rate for the three months ended June 30, 2017 were $0.2 million relating to return to provision adjustments. These items were offset by $8.4 million relating to operating in higher tax rate jurisdictions, $2.6 million related to a net decrease to the Company's valuation allowances in Canada due to income and $0.6 million relating to foreign exchange.

Income tax benefit for the three months ended June 30, 2016 was $18.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $9.0 million. The primary items impacting the tax rate for the three months ended June 30, 2016 were $4.6 million related to capital gain on intercompany notes, $2.6 million related to foreign exchange, $1.8 million relating to a change in the valuation allowance and $0.4 million of other permanent differences. These items were offset by $18.8 million related to capital loss recognized on tax restructuring.

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Six months ended June 30, 2017 compared to the six months ended June 30, 2016

The following table provides our consolidated results of operations:

	Six months ended June 30,				
	2017	2016	$ change	% change	
Project revenue:					
Energy sales	$ 77.1	$ 97.6	$ (20.5)	(21.0)	%
Energy capacity revenue	47.8	69.2	(21.4)	(30.9)	%
Other	97.5	37.8	59.7	157.9	%
	222.4	204.6	17.8	8.7	%
Project expenses:					
Fuel	52.9	74.0	(21.1)	(28.5)	%
Operations and maintenance	43.6	51.2	(7.6)	(14.8)	%
Depreciation and amortization	59.0	50.3	8.7	17.3	%
	155.5	175.5	(20.0)	(11.4)	%
Project other expense:					
Change in fair value of derivative instruments	(3.9)	11.0	(14.9)	(135.5)	%
Equity in (loss) earnings of unconsolidated affiliates	(45.4)	18.3	(63.7)	NM	
Interest expense, net	(4.4)	(4.5)	0.1	(2.2)	%
	(53.7)	24.8	(78.5)	NM	
Project income	13.2	53.9	(40.7)	(75.5)	%
Administrative and other expenses (income):					
Administration	12.1	11.9	0.2	1.7	%
Interest expense, net	35.7	67.8	(32.1)	(47.3)	%
Foreign exchange loss	8.3	22.5	(14.2)	(63.1)	%
Other income, net	—	(2.2)	2.2	(100.0)	%
	56.1	100.0	(43.9)	(43.9)	%
Loss from continuing operations before income taxes	(42.9)	(46.1)	3.2	(6.9)	%
Income tax benefit	(22.6)	(16.8)	(5.8)	34.5	%
Net loss	(20.3)	(29.3)	9.0	NM	
Net income attributable to Preferred share dividends of a subsidiary company	4.3	4.2	0.1	2.4	%
Net loss attributable to Atlantic Power Corporation	$ (24.6)	$ (33.5)	$ 8.9	NM	

The following tables provide our project income by segment:

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	Six months ended June 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 46.2	$ 16.2	$ 14.7	$ —	$ 77.1
Energy capacity revenue	22.5	20.0	5.3	—	47.8
Other	7.8	15.1	74.1	0.5	97.5
	76.5	51.3	94.1	0.5	222.4
Project expenses:					
Fuel	23.1	22.1	7.7	—	52.9
Operations and maintenance	16.7	13.2	13.7	—	43.6
Depreciation and amortization	17.8	14.6	26.3	0.3	59.0
	57.6	49.9	47.7	0.3	155.5
Project other income (expense):					
Change in fair value of derivative instruments	(1.3)	—	(4.1)	1.5	(3.9)
Equity in loss of unconsolidated affiliates	(44.0)	(1.4)	—	—	(45.4)
Interest expense, net	(4.4)	—	—	—	(4.4)
Other expense, net	—	—	—	—	—
	(49.7)	(1.4)	(4.1)	1.5	(53.7)
Project (loss) income	$ (30.8)	$ —	$ 42.3	$ 1.7	$ 13.2

	Six months ended June 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 39.9	$ 14.0	$ 43.7	$ —	$ 97.6
Energy capacity revenue	24.8	19.9	24.5	—	69.2
Other	8.4	10.6	18.3	0.5	37.8
	73.1	44.5	86.5	0.5	204.6
Project expenses:					
Fuel	25.7	15.9	32.4	—	74.0
Operations and maintenance	19.0	13.0	18.5	0.7	51.2
Depreciation and amortization	17.0	14.6	18.4	0.3	50.3
	61.7	43.5	69.3	1.0	175.5
Project other income (expense):					
Change in fair value of derivative instruments	1.7	—	12.1	(2.8)	11.0
Equity in earnings of unconsolidated affiliates	17.0	1.3	—	—	18.3
Interest expense, net	(4.5)	—	—	—	(4.5)
	14.2	1.3	12.1	(2.8)	24.8
Project income (loss)	$ 25.6	$ 2.3	$ 29.3	$ (3.3)	$ 53.9

East U.S.

Project income for the six months ended June 30, 2017 decreased $56.4 million from the comparable 2016 period primarily due to:

- decreased project income of $47.4 million and $11.0 million at Chambers and Selkirk, respectively, primarily due to impairments of $47.1 million and $10.6 million recorded in the six months ended June 30, 2017;
- decreased project income of $6.8 million at Orlando primarily due to a $8.5 million decrease in the change in fair value of derivatives and a maintenance outage, partially offset by lower fuel expense resulting from the settlement of favorable fuel swaps; and
- decreased project income of $3.7 million at Morris primarily due to higher fuel prices and lower energy and

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capacity revenue than in the comparable 2016 period.

These decreases were partially offset by:

- increased project income of $6.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period; and
- increased project income of $5.1 million at Piedmont primarily due to a $3.4 million increase in the change in fair value of interest rate swap agreements, as well as a maintenance outage that occurred in the comparable 2016 period.

West U.S.

Project income for the six months ended June 30, 2017 decreased $2.3 million from the comparable 2016 period primarily due to:

- decreased project income of $2.3 million at Frederickson primarily due to higher planned maintenance expense than the comparable 2016 period.

Canada

Project income for the six months ended June 30, 2017 increased $13.0 million from the comparable 2016 period primarily due to:

- increased project income of $20.3 million at Kapuskasing, North Bay and Tunis, primarily due to approximately $24.7 million of revenue recorded related to the OEFC settlement, $22.6 million of lower fuel expense due to the expiration of fuel purchase agreements in December 2016 as well as to the enhanced dispatch agreements, and $3.9 million of lower maintenance expense due to the plants not being operational under the enhanced dispatch agreements. These increases were partially offset by a negative $13.8 million change in the fair value of gas purchase agreements that expired in December 2016 and were accounted for as derivatives and $8.0 million of accelerated depreciation at North Bay and Kapuskasing in the six months ended June 30, 2017.

These increases were partially offset by:

- decreased project income of $3.6 million at Mamquam primarily due to a forced outage that occurred in the three months ended June 30, 2017; and

- decreased project income of $2.5 million at Calstock primarily due to lower waste heat revenue and higher fuel prices than the comparable 2016 period.

Un allocated Corporate

Total project income for the six months ended June 30, 2017 was $1.7 million compared to a total project loss of $3.3 million in the comparable 2016 period. The change was primarily due to a $4.3 million increase in the fair value of fuel swaps and gas purchase agreements accounted for as derivatives.

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.

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Administration

Administration expense did not change materially from the 2016 comparable period.

Interest expense, net

Interest expense decreased $32.1 million from the comparable 2016 period primarily due to the write-off of $31.4 million of deferred financing costs related to the senior secured credit facilities and repurchase and cancellation of convertible debentures during the six months ended June 30, 2016, as well as lower outstanding debt balances at June 30, 2017.

Foreign exchange loss

Foreign exchange loss for the six months ended June 30, 2017 decreased $14.2 million from the comparable 2016 period primarily due to a $14.7 million decrease in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The repurchase and cancellation of Cdn$152.1 million Canadian dollar-denominated convertible debentures during the three months ended June 30, 2016 was the most significant factor in the decrease. The closing U.S. dollar to Canadian dollar exchange rates were 1.30 and 1.29 at June 30, 2017 and 2016, respectively, a decrease of 3.3% during the six months ended June 30, 2017, as compared to a decrease of 6.7% in the comparable 2016 period. The average U.S. dollar to Canadian dollar exchange rates were 1.33 and 1.32 for the six months ended June 30, 2017 and 2016, respectively.

Other income, net

Other income, net decreased $2.2 million primarily due to a gain recorded on the purchase and cancellation of convertible debentures in the comparable 2016 period.

Income tax expense

Income tax benefit for the six months ended June 30, 2017 was $22.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $11.2 million. The primary items impacting the tax rate for the six months ended June 30, 2017 were $0.3 million relating to return to provision adjustments. These items were offset by $8.7 million relating to operating in higher tax rate jurisdictions, $1.9 million related to a net decrease to the Company's valuation allowances in Canada due to income, $1.0 million relating to foreign exchange and $0.1 million of other permanent differences.

Income tax benefit for the six months ended June 30, 2016 was $16.8 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.0 million. The primary items impacting the tax rate for the six months ended June 30, 2016 were $5.1 million relating to foreign exchange, $4.6 million relating to a change in the valuation allowance, $4.2 million related to capital gain on intercompany notes and $0.1 million of other permanent differences. These items were offset by $18.8 million related to capital loss recognized on tax restructuring.

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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 and six months ended June 30, 2017. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in Net Gigawatt-hours (GWh).

	Generation			
	Three months ended June 30,			
			% change	
(in Net GWh)	2017	2016	2017 vs. 2016	
Segment				
East U.S.	612.1	614.7	(0.4)	%
West U.S.	270.5	360.1	(24.9)	%
Canada	246.8	501.1	(50.7)	%
Total	1,129.4	1,475.9	(23.5)	%

Three months ended June 30, 2017 compared with three months ended June 30, 2016

Aggregate power generation for the three months ended June 30, 2017 decreased 23.5% from the comparable 2016 period primarily due to:

· decreased generation in the Canada segment primarily due to a decrease of 216.0 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, due to their suspended operation status under the enhanced dispatch contracts, and a 36.2 net GWh decrease in generation at Mamquam due to lower water flows and a forced outage in the three months ended June 30, 2017; and

· decreased generation in the West U.S. segment primarily due to a 69.1 net GWh decrease in generation at Frederickson due to lower merchant demand; and

· decreased generation in the East U.S. segment primarily due to a 23.3 net GWh decrease in generation at Orlando due to a maintenance outage and a 20.4 net GWh decrease in generation at Morris due to lower merchant demand, offset by a 50.2 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable period in 2016.

	Generation Six months ended June 30,			
(in Net GWh)	2017	2016	% change 2017 vs. 2016	
Segment				
East U.S.	1,203.5	1,278.7	(5.9)	%
West U.S.	621.2	702.7	(11.6)	%
Canada	458.5	1,044.9	(56.1)	%
Total	2,283.2	3,026.3	(24.6)	%

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Aggregate power generation for the six months ended June 30, 2017 decreased 24.6% from the comparable 2016 period primarily due to:

· decreased generation in the Canada segment primarily due to a decrease of 484.2 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, primarily due to their suspended operation status under the enhanced dispatch contracts, and a 74.7 net GWh decrease in generation at Mamquam due to lower water flows and a forced outage in the three months ended June 30, 2017;

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· decreased generation in the West U.S. segment primarily due to a 79.5 net GWh decrease in generation at Frederickson due to lower merchant demand; and

· decreased generation in the East U.S. segment primarily due to a 53.6 net GWh decrease in generation at Morris due to lower merchant demand and a 44.6 net GWh decrease in generation at Orlando due to a maintenance outage, offset by a 48.3 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable period in 2016.

	Availability Three months ended June 30,					
	2017		2016		% change 2017 vs. 2016	
Segment						
East U.S.	87.8	%	92.7	%	(5.3)	%
West U.S.	79.6	%	90.6	%	(12.1)	%
Canada	87.0	%	95.1	%	(8.5)	%
Weighted average	85.2	%	92.7	%	(8.1)	%

Three months ended June 30, 2017 compared with three months ended June 30, 2016

Aggregate power availability for the three months ended June 30, 2017 decreased 8.1% from the comparable 2016 period primarily due to:

· decreased availability in the Canada segment primarily due to a forced outage at Mamquam;

· decreased availability in the West U.S. segment primarily due to planned maintenance outages at Frederickson; and

· decreased availability in the East U.S. segment primarily due to a planned maintenance outage at Kenilworth and Morris.

	Availability Six months ended June 30,					
	2017		2016		% change 2017 vs. 2016	
Segment						
East U.S.	91.8	%	95.9	%	(4.3)	%
West U.S.	87.1	%	90.1	%	(3.3)	%

Canada	88.9 %	97.3 %	(8.6)	%
Weighted average	90.1 %	94.6 %	(4.8)	%

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Aggregate power availability for the six months ended June 30, 2017 decreased 4.8% from the comparable 2016 period primarily due to:

· decreased availability in the Canada segment primarily due to a forced outage at Mamquam;

· decreased availability in the West U.S. segment primarily due to a planned maintenance outage at Frederickson; and

· decreased availability in the East U.S. segment primarily due to planned maintenance outages at Kenilworth and Morris.

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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 (loss) income 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.

Project Adjusted EBITDA

	Three months ended June 30,		$ change 2017 vs 2016	Six months ended June 30,		$ change 2017 vs 2016
	2017	2016		2017	2016	
Net loss	$ (19.8)	$ (16.3)	$ (3.5)	$ (20.3)	$ (29.3)	$ 9.0
Income tax benefit	(22.3)	(18.4)	(3.9)	(22.6)	(16.8)	(5.8)
Loss from operations before income taxes	(42.1)	(34.7)	(7.4)	(42.9)	(46.1)	3.2
Administration	5.7	5.8	(0.1)	12.1	11.9	0.2
Interest expense, net	18.4	51.2	(32.8)	35.7	67.8	(32.1)
Foreign exchange loss	5.9	2.6	3.3	8.3	22.5	(14.2)
Other expense (income), net	—	0.3	(0.3)	—	(2.2)	2.2
Project (loss) income	$ (12.1)	$ 25.2	$ (37.3)	$ 13.2	$ 53.9	$ (40.7)
Reconciliation to Project Adjusted EBITDA						
Depreciation and amortization	34.7	30.4	4.3	69.3	60.3	9.0
Interest expense, net	2.5	2.9	(0.4)	5.3	5.4	(0.1)
Change in the fair value of derivative instruments	2.6	(12.2)	14.8	3.8	(11.0)	14.8
Other (income) expense	—	(0.1)	0.1	—	0.1	(0.1)
Impairment	57.7	—	57.7	57.7	—	57.7
Project Adjusted EBITDA	$ 85.4	$ 46.2	$ 39.2	$ 149.3	$ 108.7	$ 40.6

Project Adjusted EBITDA by segment						
East U.S.	29.1	20.9	8.2	56.2	51.2	5.0
West U.S.	10.6	14.5	(3.9)	19.8	22.0	(2.2)
Canada	45.2	10.9	34.3	72.8	35.7	37.1
Un-Allocated Corporate	0.5	(0.1)	0.6	0.5	(0.2)	0.7
Total	85.4	46.2	39.2	149.3	108.7	40.6

East U.S.

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

	Three months ended June 30,		
	2017	2016	% change 2017 vs. 2016
East U.S.			
Project Adjusted EBITDA	$ 29.1	$ 20.9	39 %

Three months ended June 30, 2017 compared with three months ended June 30, 2016

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Project Adjusted EBITDA for the three months ended June 30, 2017 increased $8.2 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- $6.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period; and
- $1.3 million at Piedmont primarily due to a maintenance outage that occurred in the comparable 2016 period.

	Six months ended June 30,		
	2017	2016	% change 2017 vs. 2016
East U.S.			
Project Adjusted EBITDA	$ 56.2	$ 51.2	10 %

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Project Adjusted EBITDA for the six months ended June 30, 2017 increased $5.0 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- $6.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period;
- $1.9 million at Piedmont primarily due to a maintenance outage that occurred in the comparable 2016 period; and
- $1.7 million at Orlando primarily due to lower fuel expenses resulting from the settlement of favorable fuel swaps.

These increases were partially offset by a decrease in Project Adjusted EBITDA of:

- $5.0 million at Morris primarily due to lower energy and capacity prices than the comparable 2016 period.

West U.S.

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

	Three months ended June 30,		
	2017	2016	% change 2017 vs 2016
West U.S.			
Project Adjusted EBITDA	$ 10.6	$ 14.5	(27) %

Three months ended June 30, 2017 compared with three months ended June 30, 2016

Project Adjusted EBITDA for the three months ended June 30, 2017 decreased $3.9 million from the comparable 2016 period primarily due to decreased Project Adjusted EBITDA of:

- $2.7 million at Frederickson primarily due to higher planned maintenance expense than the comparable 2016 period;

- $0.7 million at Naval Station primarily due to lower steam revenue than the comparable 2016 period; and

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- $0.6 million at North Island primarily due to a maintenance outage that occurred during the three months ended June 30, 2017, as well as lower margins from higher fuel prices.

	Six months ended June 30,		
	2017	2016	% change 2017 vs 2016
West U.S.			
Project Adjusted EBITDA	$ 19.8	$ 22.0	(10) %

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Project Adjusted EBITDA for the six months ended June 30, 2017 decreased $2.2 million from the comparable 2016 period primarily due to decreased Project Adjusted EBITDA of:

- $2.3 million at Frederickson primarily due to higher planned maintenance expense than the comparable 2016 period.

Canada

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

	Three months ended June 30,		
	2017	2016	% change 2017 vs. 2016
Canada			
Project Adjusted EBITDA	$ 45.2	$ 10.9	NM

Three months ended June 30, 2017 compared with three months ended June 30, 2016

Project Adjusted EBITDA for the three months ended June 30, 2017 increased $34.3 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

· $35.4 million at Kapuskasing, North Bay and Tunis, primarily due to the OEFC settlement, which resulted in $24.7 million of additional revenue recorded in the three months ended June 30, 2017. Additionally, the terms of the enhanced dispatch contracts and the expiration of unfavorable fuel purchase agreements on December 31, 2016 resulted in a total $10.8 million of increased Project Adjusted EBITDA at North Bay and Kapuskasing from the comparable 2016 period.

These increases were partially offset by a decrease in Project Adjusted EBITDA of:

· $1.7 million at Mamquam primarily due to a forced outage that occurred during the three months ended June 30, 2017, as well as to lower water flows than the comparable 2016 period.

	Six months ended June 30,			
			% change	
	2017	2016	2017 vs. 2016	
Canada				
Project Adjusted EBITDA	$ 72.8	$ 35.7	104	%

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Project Adjusted EBITDA for the six months ended June 30, 2017 increased $37.1 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

· $42.2 million at Kapuskasing, North Bay and Tunis, primarily due to the OEFC settlement, which resulted in $24.7 million of additional revenue recorded in the six months ended June 30, 2017. Additionally, the terms of the enhanced dispatch contracts and the expiration of unfavorable fuel purchase agreements on December 31, 2016 resulted in a total $17.6 million of increased Project Adjusted EBITDA at North Bay

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and Kapuskasing from the comparable 2016 period.

These increases were partially offset by decreases in Project Adjusted EBITDA of:

- $3.6 million at Mamquam primarily due to a forced outage that occurred during the three months ended June 30, 2017, as well as to lower water flows than the comparable 2016 period; and

- $2.5 million at Calstock primarily due to lower waste heat revenue and higher fuel prices than the comparable 2016 period.

Un allocated Corporate

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

	Three months ended June 30,		
	2017	2016	% change 2017 vs. 2016
Un-allocated Corporate Project Adjusted EBITDA	$ 0.5	$ (0.1)	NM

Three months ended June 30, 2017 compared with three months ended June 30, 2016

Project Adjusted EBITDA for the three months ended June 30, 2017 did not change materially from the comparable 2016 period.

	Six months ended June 30,		
	2017	2016	% change 2017 vs. 2016
Un-allocated Corporate Project Adjusted EBITDA	$ 0.5	$ (0.2)	NM

Six months ended June 30, 2017 compared with six months ended June 30, 2016

Project Adjusted EBITDA for the six months ended June 30, 2017 did not change materially from the comparable 2016 period.

Liquidity and Capital Resources

	June 30, 2017	December 31, 2016
Cash and cash equivalents	$ 104.4	$ 85.6
Restricted cash	14.1	13.3
Total	118.5	98.9
Revolving credit facility availability	122.8	118.5
Total liquidity	$ 241.3	$ 217.4

Overview

Our primary sources of liquidity are distributions from our projects and availability under our revolving credit facility. Our future liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from December 31, 2017 (at our North Bay and Kapuskasing projects) to December 2037. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements or we may elect to operate certain facilities in the merchant market upon expiration of their PPAs. 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

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and investment in accretive growth opportunities (both internal and external), to the extent available, repurchase of common shares 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 external growth opportunities or fund our operations” in our Annual Report on Form 10 K for the year ended December 31, 2016.

We expect to reinvest approximately $46.7 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2017, of which $22.6 million has been incurred through June 30, 2017. Such investments are generally paid at the project level. See “—Capital and Major Maintenance Expenditures” in our Annual Report on Form 10 K for the year ended December 31, 2016. We do not expect any other material or unusual requirements for cash outflows for 2017 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:

	Six months ended June 30,		
	2017	2016	Change
Net cash provided by operating activities	$ 85.0	$ 53.7	$ 31.3
Net cash (used in) provided by investing activities	(5.0)	3.6	(8.6)
Net cash (used in) provided by financing activities	(61.2)	24.5	(85.7)

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 six months ended June 30, 2017, the net increase in cash flows from operating activities of $31.3 million was primarily the result of the following:

· OEFC Settlement – we received approximately $24.7 million related to our settlement with the OEFC in the six months ended June 30, 2017;

· Impact of enhanced dispatch contracts and lower fuel costs in Ontario – we recorded $10.0 million of higher gross margin at North Bay, Kapuskasing and Nipigon as a result of the enhanced dispatch contracts and the expiration of unfavorable gas purchase agreements at North Bay and Kapuskasing in December 2016; and

· Hydrological conditions at Curtis Palmer – higher water flows at our Curtis Palmer project had a $6.5 million impact on cash flows from operations.

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

· Demand and fuel prices – lower energy and capacity prices at Morris and higher maintenance expense at Frederickson, as well as higher fuel prices resulted in a $7.3 million decrease in cash flows from operating activities from the comparable 2016;

· Hydrological conditions and maintenance outage at Mamquam – lower water flows and a forced outage at our Mamquam project had a $3.6 million impact on cash flows from operations; and

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· Waste heat – lower waste heat at our Calstock project had a $2.5 million impact on cash flows from operations.

Investing Activities

For the six months ended June 30, 2017, the net decrease in cash flows used in investing activities of $8.6 million was primarily the result of the following:

· Reimbursement of construction cost – we received a reimbursement of $4.7 million for the construction project at Morris in the comparable 2016 period;

· Purchase of property, plant and equipment – we made investments in capitalized plant additions that were $2.2 million higher in the six months ended June 30, 2017 as compared to the comparable 2016 period; and

· Restricted cash – the change in restricted cash decreased $1.7 million from the comparable 2016 period, primarily due to lower restricted cash requirements from decreased outstanding debt balances.

Financing Activities

For the six months ended June 30, 2017, the net decrease in cash flows from financing activities of $85.7 million was primarily the result of the following:

· The Credit Facilities – we received $231.1 million of net proceeds from issuance of the senior secured term loan in the comparable 2016 period after repayment of the previous term loan;

· Convertible debenture repayments – we paid $127.0 million to redeem and cancel convertible debentures in the comparable 2016 period;

· Deferred financing costs – we incurred $15.9 million of deferred financing costs related to the refinancing of the senior secured credit facilities in the comparable 2016 period; and

· Common share repurchases – we paid $4.7 million to repurchase and cancel common shares in the comparable 2016 period.

Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2017:

	Maturity Date	Interest Rates		Remaining Principal Repayments	2017	2018	2019	2020	2021	Thereafter
Senior secured term loan facility(1)	April 2023	5.40 %	- 5.50 %	$ 587.7	$ 50.0	$ 90.0	$ 65.0	$ 105.0	$ 80.0	$ 199.9
Atlantic Power Income LP Note	June 2036	5.95 %		161.8	—	—	—	—	—	161.8
Convertible Debenture	June 2019	5.75 %		42.5	—	—	42.5	—	—	—
Convertible Debenture	December 2019	6.00 %		62.4	—	—	62.4	—	—	—
Total Corporate Debt				$ 854.4	$ 50.0	$ 90.0	$ 169.9	$ 105.0	$ 80.0	$ 361.7

(1) The senior secured term loans contain a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings Limited Partnership (“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 senior secured credit facilities and the Medium Term Notes, 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., 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 senior secured 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

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event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited 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.

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 June 30, 2017. 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 August 1, 2017, all of our projects with the exception of Piedmont 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. We do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before the project's debt maturity in 2018 at the earliest. See Note 6 to the consolidated financial statements of this Quarterly Report on Form 10-Q, Long term debt—Non Recourse Debt.

The range of interest rates presented represents the rates in effect at June 30, 2017. 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	2017	2018	2019	2020	2021	Thereafter
Consolidated Projects:									
Epsilon Power Partners	January 2019	4.20 %	$ 10.4	$ 3.1	$ 6.5	$ 0.7	$ —	$ —	$ —
Piedmont	August 2018	8.10 %	56.6	2.5	54.1	—	—	—	—
Cadillac	August 2025	6.14 %	25.5	1.5	3.0	3.1	3.1	2.7	12.1
Total Consolidated Projects			92.5	7.1	63.6	3.8	3.1	2.7	12.1
Equity Method Projects:									
Chambers(1)		4.50 % - 5.00 %	42.9	—	—	5.2	7.8	8.8	21.1

	December 2019 and 2023							
Total Equity Method Projects		42.9	—	—	5.2	7.8	8.8	21.1
Total Project-Level Debt		$ 135.4	$ 7.1	$ 63.6	$ 9.0	$ 10.9	$ 11.5	$ 33.2

(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 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, Medium Term Notes 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.

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We expect to reinvest approximately $5.5 million in 2017 (of which $4.8 million was reinvested in the six months ended June 30, 2017) in our portfolio in the form of project capital expenditures and incur $41.2 million of maintenance expenses (of which $17.8 million was incurred in the six months ended June 30, 2017). Such investments are generally paid at the project level. See "—Capital and Major Maintenance Expenditures" in our Annual Report on Form 10 K for the year ended December 31, 2016. We do not expect any other material or unusual requirements for cash outflows for 2017 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 2017 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 June 30, 2017, 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, 2016.

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.

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the six months ended June 30, 2017, 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.

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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, 2016 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, 2016 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.

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.39	Amendment dated April 17, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to our Quarterly Report on Form 10-Q filed on May 4, 2017)
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

*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: August 3, 2017	Atlantic Power Corporation		
	By:	/s/ Terrence Ronan	
		Name:	Terrence Ronan
		Title:	Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)