ATLANTIC POWER CORP
Form 10-Q
November 07, 2016
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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 September 30, 2016

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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 November 4, 2016 was 115,635,212.

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ATLANTIC POWER CORPORATION

FORM 10 Q

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016

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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)

	September 30, 2016 (unaudited)	December 31, 2015
Assets		
Current assets:		
Cash and cash equivalents	$ 93.8	$ 72.4
Restricted cash	12.6	15.2
Accounts receivable	39.5	39.6
Current portion of derivative instruments asset (Notes 8 and 9)	1.6	—
Inventory	15.9	16.9
Prepayments	10.1	8.3
Other current assets	2.5	4.5
Total current assets	176.0	156.9
Property, plant, and equipment, net of accumulated depreciation of $279.2 million and $236.3 million at September 30, 2016 and December 31, 2015, respectively	749.8	777.7
Equity investments in unconsolidated affiliates (Note 5)	277.6	286.2
Power purchase agreements and intangible assets, net of accumulated amortization of $282.5 million and $238.0 million at September 30, 2016 and December 31, 2015, respectively	273.0	308.9
Goodwill (Note 3)	37.6	134.5
Derivative instruments asset (Notes 8 and 9)	1.3	0.3
Deferred income taxes	1.0	—
Other assets	5.6	6.7
Total assets	$ 1,521.9	$ 1,671.2
Liabilities		
Current liabilities:		
Accounts payable	$ 3.7	$ 6.9
Accrued interest	10.9	1.6
Other accrued liabilities	24.3	25.4
Current portion of long-term debt (Note 6)	101.4	15.8
Current portion of derivative instruments liability (Notes 8 and 9)	15.2	36.7
Other current liabilities	4.1	2.5
Total current liabilities	159.6	88.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 6)	778.9	682.7
Convertible debentures, net of unamortized deferred financing costs (Note 7)	101.4	277.7

Derivative instruments liability (Notes 8 and 9)	27.3	20.8
Deferred income taxes	69.8	85.7
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $15.9 million and $14.0 million at September 30, 2016 and December 31, 2015, respectively	26.2	27.0
Other long-term liabilities	54.9	53.2
Total liabilities	1,218.1	1,236.0
Equity		
Common shares, no par value, unlimited authorized shares; 117,029,308 and 122,153,082 issued and outstanding at September 30, 2016 and December 31, 2015, respectively (Note 13)	1,278.1	1,290.6
Accumulated other comprehensive loss (Note 2)	(142.0)	(139.3)
Retained deficit (Note 13)	(1,053.6)	(937.4)
Total Atlantic Power Corporation shareholders' equity	82.5	213.9
Preferred shares issued by a subsidiary company (Note 13)	221.3	221.3
Total equity	303.8	435.2
Total liabilities and equity	$ 1,521.9	$ 1,671.2

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Project revenue:				
Energy sales	$ 40.7	$ 43.4	$ 138.4	$ 144.9
Energy capacity revenue	44.0	45.9	113.2	117.4
Other	16.5	18.2	54.2	59.5
	101.2	107.5	305.8	321.8
Project expenses:				
Fuel	36.8	41.1	110.8	125.3
Operations and maintenance	28.2	24.8	79.4	81.6
Development	—	—	—	1.1
Depreciation and amortization	25.3	27.8	75.6	83.8
	90.3	93.7	265.8	291.8
Project other income (loss):				
Change in fair value of derivative instruments (Notes 8 and 9)	9.0	3.6	20.0	8.7
Equity in earnings of unconsolidated affiliates (Note 5)	9.6	8.9	27.9	28.3
Interest, net	(2.4)	(2.1)	(6.9)	(6.2)
Impairment (Note 3)	(84.7)	—	(84.7)	—
Other income, net	0.5	—	0.4	2.2
	(68.0)	10.4	(43.3)	33.0
Project (loss) income	(57.1)	24.2	(3.3)	63.0
Administrative and other expenses (income):				
Administration	5.7	6.9	17.6	23.0
Interest, net	20.0	41.0	87.9	91.3
Foreign exchange (gain) loss	(3.4)	(21.7)	19.1	(49.1)
Other income, net (Note 7)	(1.7)	—	(3.9)	(3.1)
	20.6	26.2	120.7	62.1
(Loss) income from continuing operations before income taxes	(77.7)	(2.0)	(124.0)	0.9
Income tax expense (benefit) (Note 10)	2.6	1.4	(14.2)	(0.3)
(Loss) income from continuing operations	(80.3)	(3.4)	(109.8)	1.2
Net (loss) income from discontinued operations, net of tax (Note 4)	—	(0.5)	—	20.6

Net (loss) income	(80.3)	(3.9)	(109.8)	21.8
Net loss attributable to noncontrolling interests	—	—	—	(11.0)
Net income attributable to preferred shares dividends of a subsidiary company	2.1	2.1	6.4	6.7
Net (loss) income attributable to Atlantic Power Corporation	$ (82.4)	$ (6.0)	$ (116.2)	$ 26.1
Basic and diluted (loss) income per share: (Note 12)				
Loss from continuing operations attributable to Atlantic Power Corporation	$ (0.69)	$ (0.05)	$ (0.96)	$ (0.05)
Income from discontinued operations, net of tax	—	—	—	0.26
Net (loss) income attributable to Atlantic Power Corporation	$ (0.69)	$ (0.05)	$ (0.96)	$ 0.21
Weighted average number of common shares outstanding: (Note 12)				
Basic	119.3	122.1	120.9	121.8
Diluted	119.3	122.2	120.9	121.9
Dividends per common share:	$ —	$ 0.02	$ —	$ 0.07

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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net (loss) income	$ (80.3)	$ (3.9)	$ (109.8)	$ 21.8
Other comprehensive (loss) income, net of tax:				
Unrealized (loss) gain on hedging activities	$ —	$ (0.4)	$ (0.6)	$ (0.8)
Net amount reclassified to earnings	0.2	0.2	0.5	0.6
Net unrealized gain (loss) on derivatives	0.2	(0.2)	(0.1)	(0.2)
Foreign currency translation adjustments	(22.0)	(22.1)	(2.6)	(52.7)
Other comprehensive loss, net of tax	(21.8)	(22.3)	(2.7)	(52.9)
Comprehensive loss	(102.1)	(26.2)	(112.5)	(31.1)
Less: Comprehensive income (loss) attributable to noncontrolling interests	2.1	2.1	6.4	(4.3)
Comprehensive loss attributable to Atlantic Power Corporation	$ (104.2)	$ (28.3)	$ (118.9)	$ (26.8)

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)

	Nine months ended September 30, 2016	2015
Cash provided by operating activities:		
Net (loss) income	$ (109.8)	$ 21.8
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation and amortization	75.6	94.1
Gain from discontinued operations	—	(47.2)
Gain on sale of development project and other assets	—	(2.3)
Gain on purchase and cancellation of convertible debentures	(4.7)	(3.1)
Loss on disposal of fixed assets	0.2	—
Stock-based compensation expense	1.4	2.1
Long-lived asset and goodwill impairment	84.7	—
Equity in earnings from unconsolidated affiliates	(27.9)	(28.3)
Distributions from unconsolidated affiliates	36.5	40.0
Unrealized foreign exchange loss (gain)	19.1	(49.3)
Change in fair value of derivative instruments	(20.0)	(8.0)
Change in deferred income taxes	(16.8)	23.6
Change in other operating balances		
Accounts receivable	—	4.3
Inventory	1.1	1.7
Prepayments and other assets	42.1	20.2
Accounts payable	0.3	(6.1)
Accruals and other liabilities	10.1	4.2
Cash provided by operating activities:	91.9	67.7
Cash provided by investing activities:		
Change in restricted cash	2.6	8.0
Proceeds from sale of assets and equity investments, net	—	326.3
Contribution to unconsolidated affiliate	—	(0.5)
Capitalized development costs	—	(0.8)
Reimbursement of costs for third-party construction project	4.7	—
Purchase of property, plant and equipment	(6.5)	(9.4)

Cash provided by investing activities	0.8	323.6
Cash used in financing activities:		
Proceeds from senior secured term loan facility, net of discount	679.0	—
Common share repurchases	(13.9)	—
Repayment of corporate and project-level debt	(526.4)	(387.1)
Repayment of convertible debentures	(187.4)	(18.7)
Deferred financing costs	(16.2)	—
Dividends paid to common shareholders	—	(8.5)
Dividends paid to noncontrolling interests	—	(3.8)
Dividends paid to preferred shareholders	(6.4)	(6.7)
Cash used in financing activities	(71.3)	(424.8)
Increase (decrease) in cash and cash equivalents	21.4	(33.5)
Less cash at discontinued operations	—	3.9
Cash and cash equivalents at beginning of period at discontinued operations	—	—
Cash and cash equivalents at beginning of period	72.4	106.0
Cash and cash equivalents at end of period	$ 93.8	$ 76.4
Supplemental cash flow information		
Interest paid	$ 43.3	$ 75.5
Income taxes paid, net	$ 2.8	$ 4.1
Accruals for construction in progress	$ 0.4	$ 1.2

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 September 30, 2016, our power generation projects in operation 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 operational power generation projects across nine states in the United States and two provinces in Canada. Eighteen of our projects are majority owned subsidiaries.

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 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, 2015. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of September 30, 2016, the results of operations and comprehensive loss for the three and nine months ended September 30, 2016 and 2015, and our cash flows for the nine months ended September 30, 2016 and 2015 in accordance with U.S generally accepted accounting policies. In the opinion of management, all adjustments (consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the 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, 2015. 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 January 2015, the Financial Accounting Standards Board ("FASB") issued changes to the presentation of extraordinary items. Such items are defined as transactions or events that are both unusual in nature and infrequent in occurrence, and, currently, are required to be presented separately in an entity's statement of operations, net of income tax, after income from continuing operations. The changes eliminate the concept of an extraordinary item and, therefore, the presentation of such items will no longer be required. Notwithstanding this change, an entity will still be required to present and disclose a transaction or event that is both unusual in nature and infrequent in occurrence in the notes to the financial statements. These changes became effective for us on January 1, 2016. The adoption of these changes did not have an impact on the consolidated financial statements.

In February 2015, the FASB issued changes to the analysis that an entity must perform to determine whether it should consolidate certain types of legal entities. These changes (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (ii) eliminate the presumption that a general partner should consolidate a limited partnership, (iii) affect the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships, and (iv) provide a scope exception from consolidation guidance for reporting entities with interests in legal entities that are required to comply with or operate in accordance with requirements that are similar to those in Rule 2a-7 of the Investment Company Act of 1940 for registered money market funds. These changes became effective for us on January 1, 2016. The adoption of these changes did not have an impact on the consolidated financial statements.

In April 2015, the FASB issued changes to the presentation of debt issuance costs. Currently, such costs are required to be presented as a noncurrent asset in an entity's balance sheet and amortized into interest expense over the term of the related debt instrument. The changes require that debt issuance costs be presented in an entity's balance sheet as a direct deduction from the carrying value of the related debt liability. The amortization of debt issuance costs remains unchanged. These changes became effective for us on January 1, 2016. As a result, we have presented $19.5 million and $42.5 million of deferred financing costs as a direct deduction from long-term debt and convertible debentures for the periods ended September 30, 2016 and December 31, 2015, respectively.

In September 2015, the FASB issued new guidance on adjustments to provisional amounts recognized in a business combination, which are currently recognized on a retrospective basis. Under the new requirements, adjustments will be recognized in the reporting period in which the adjustments are determined. The effects of changes in depreciation, amortization, or other income arising from changes to the provisional amounts, if any, are included in earnings of the reporting period in which the adjustments to the provisional amounts are determined. An entity is also required to present separately on the face of the statement of operations or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

adjustment to the provisional amounts had been recognized as of the acquisition date. The new requirements became effective for us beginning January 1, 2016. We will apply this new guidance to any future business combinations.

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 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 and which implementation approach to select.

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 become effective for us on January 1, 2017. Management has determined that the adoption of these changes will not have a material 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 will be effective for us in fiscal years beginning after December 15, 2016 and is not expected to have a material impact on the consolidated financial statements.

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 are currently evaluating the potential impact on our financial position and results of operations upon adoption of this guidance.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

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 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. This guidance is effective for annual and interim reporting periods beginning after December 15, 2016, with early adoption permitted. We are currently evaluating the potential impact on our financial position and results of operations upon adoption of this guidance.

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.

2. Changes in accumulated other comprehensive loss by component

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

	Three Months Ended September 30,	Nine Months Ended September 30,

	2016	2015	2016	2015
Foreign currency translation				
Balance at beginning of period	$ (119.7)	$ (96.9)	$ (139.1)	$ (66.3)
Other comprehensive income (loss):				
Foreign currency translation adjustments(1)	(22.0)	(22.1)	(2.6)	(52.7)
Balance at end of period	$ (141.7)	$ (119.0)	$ (141.7)	$ (119.0)
Cash flow hedges				
Balance at beginning of period	$ (0.1)	$ 0.1	$ 0.2	$ 0.1
Other comprehensive income (loss):				
Net change from periodic revaluations	0.1	(0.7)	(1.0)	(1.3)
Tax (expense) benefit	(0.1)	0.3	0.4	0.5
Total Other comprehensive income before reclassifications, net of tax	—	(0.4)	(0.6)	(0.8)
Net amount reclassified to earnings:				
Interest rate swaps(2)	0.3	0.3	0.9	1.0
Tax expense	(0.1)	(0.1)	(0.4)	(0.4)
Total amount reclassified from Accumulated other comprehensive loss, net of tax	0.2	0.2	0.5	0.6
Total Other comprehensive income	0.2	(0.2)	(0.1)	(0.2)
Balance at end of period	$ 0.1	$ (0.1)	$ 0.1	$ (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. Goodwill

Our goodwill balance was $37.6 million and $134.5 million as of September 30, 2016 and December 31, 2015, respectively. We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is at the project level and, the lowest level below the operating segments for which discrete financial information is available.

In the third quarter of 2016, we performed an event-driven goodwill impairment test. While declining power prices have been observed over the past two years, we identified a significant decrease in the long-term outlook for power prices in the regions where our reporting units operate in the third quarter of 2016. Because the estimated future cash flows of our reporting units are sensitive to fluctuations in forward power prices and these prices are the most impactful input in calculating a reporting unit's fair value, we determined that it was appropriate to perform an event-driven impairment test. For two of our reporting units (Morris and Nipigon) we performed a qualitative assessment and concluded that it was likely that the fair values significantly exceed the carrying values. These reporting units have aggregate goodwill of $6.9 million and have PPAs with significant remaining time before their expiration and are not significantly impacted by the decrease in the long-term outlook for power prices.

The other five of the reporting units tested (Curtis Palmer, Mamquam, North Bay, Kapuskasing and Moresby Lake) failed step 1 of our quantitative two step test. Because five reporting units failed step 1 of the two-step goodwill impairment test, we identified a triggering event and initiated a test of the recoverability of their long-lived assets. The asset group for testing the long-lived assets for impairment is the same as the reporting unit for goodwill impairment testing purposes. In order to test the recoverability of the assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by the asset group. The carrying value of each asset group includes its recorded property, plant equipment, intangible assets related to PPAs and goodwill. Of the five asset groups tested, the North Bay and Kapuskasing asset groups (Canada segment) failed the recoverability test and we recorded property, plant and equipment impairment charges aggregating $5.9 million for the periods ended September 30, 2016. For these asset groups, we estimated their fair value utilizing an income approach based on market participant assumptions. These assumptions include estimated cash flows under the remaining period of their respective PPAs.

Subsequent to recording long-lived asset impairments, we performed the step 2 goodwill impairment test and recorded a $50.2 million full impairment at the Mamquam reporting unit, a $15.4 million partial impairment at the Curtis Palmer reporting unit, a $6.5 million full impairment at the North Bay reporting unit, a $6.7 million full impairment at the Kapuskasing reporting unit and no impairment at the Moresby Lake reporting unit for a total goodwill impairment charge of $78.8 million for the periods ended September 30, 2016. At the time of their acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Mamquam and Curtis Palmer reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original PPAs. The forecasted energy revenue on a merchant basis, in the respective markets in which those plants operate, was higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the reporting unit's PPA. Power prices, in the respective markets in which those plants operate, have declined from 2011 and from the dates of our previous impairment assessments due to several factors including decreased demand, lower oil prices and lower natural gas prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re contracting at prices than were previously forecasted in 2011. The decline in forward power prices for British Columbia since our last goodwill impairment performed as of November 30, 2015, in particular, had a significant impact on the estimated discounted cash flows of our Mamquam reporting unit and was the primary driver for its recorded goodwill impairment. British Columbia's peak demand outlook has declined primarily attributable to a reduction in forecasted liquefaction build and need in the region and the associated loss of power demand. The resulting drop in the peak demand reduces the amount of needed capacity and therefore the capacity prices also were reduced. Furthermore, the PPA at the Curtis Palmer reporting unit expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. Based on Curtis Palmer's cumulative generation through the date of the goodwill impairment test, we anticipate the PPA expiring two years before December 2027. As a result, the discounted cash flow model for Curtis Palmer utilizes forward power prices for that two-year period that are substantially lower than the prices under the current PPA.

The long-lived asset and goodwill impairment charges were recorded in the third quarter of 2016 and not earlier in the fiscal year because we did not identify any triggering events that would have required an event-driven impairment assessment. While declining power prices have been observed over the past two years, the significant decrease in the long-term outlook for power prices in the regions where our reporting units operate identified in the third quarter of 2016 had the most significant impact to the key inputs to our long-term forecasted cash flow models. Additionally, the PPAs at our North Bay and Kapuskasing reporting units expire on December 31, 2017. As these projects approach the expiration date, the remaining estimated contracted future cash flows decrease.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("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 rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our long lived asset recovery and step 1 and 2 goodwill impairment tests for our reporting units are generally based on approved reporting unit 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 reporting unit 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. We utilized the assistance of valuation experts to perform step 1 and step 2 of the quantitative impairment test for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

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The valuation of long-lived assets and goodwill for the impairment analyses is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. 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 a goodwill 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 reporting units 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.

The following table is a rollforward of goodwill for the nine months ended September 30, 2016:

Reporting unit	Segment	December 31, 2015	Impairment	Translation adjustment	September 30, 2016
Curtis Palmer	East U.S.	$ 44.5	$ (15.4)	$ —	$ 29.1
Morris	East U.S.	3.3	—	—	3.3
Kapuskasing	Canada	8.8	(6.7)	(2.1)	—
Mamquam	Canada	64.4	(50.2)	(14.2)	—
Moresby Lake	Canada	1.6	—	—	1.6
Nipigon	Canada	3.6	—	—	3.6
North Bay	Canada	8.3	(6.5)	(1.8)	—
		$ 134.5	$ (78.8)	$ (18.1)	$ 37.6

4. Discontinued operations

On June 26, 2015, Atlantic Power Transmission, Inc. (“APT”), our wholly-owned, direct subsidiary, sold our Wind Projects under a definitive agreement (the “Purchase Agreement”) with TerraForm AP Acquisition Holdings, LLC (“TerraForm”), an affiliate of SunEdison, Inc. (an affiliate of TerraForm Power, Inc.). The sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded an approximate $47.2 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the nine months ended September 30, 2015.

Terraform acquired from APT, 100% of APT’s direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. Our determination to designate the Wind Projects as discontinued operations was based on the impact the sale would have on our operations and financial results and because the Wind Projects made up the entirety of our Wind reportable segment. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

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The following table summarizes the revenue and income from operations of the Wind Projects for the three and nine months ended September 30, 2015:

	Three months ended September 30, 2015	Nine months ended September 30, 2015
Revenue	$ —	$ 34.8
Project expenses:		
Operations and maintenance	—	10.8
Depreciation and amortization	—	10.3
	—	21.1
Project other expense:		
Change in fair value of derivatives	—	(0.7)
Equity in earnings of unconsolidated affiliates	—	(0.3)
Interest expense, net	—	(6.7)
Gain (loss) on sale of asset	(0.2)	47.2
	(0.2)	39.5
Income (loss) from operations of discontinued businesses	(0.2)	53.2
Income tax expense	0.3	32.6
	(0.5)	20.6

Income (loss) from operations of discontinued businesses, net of tax				
Net loss attributable to noncontrolling interests of discontinued businesses		—		(11.0)
Income (loss) from operations of discontinued businesses, net of noncontrolling interests	$	(0.5)	$	31.6

Basic and diluted earnings per share related to income (loss) from discontinued operations for the Wind Projects was $0.00 and $0.26 for the three and nine months ended September 30, 2015, respectively.

The following table summarizes the operating and investing cash flows of the Wind Projects for the nine months ended September 30, 2015:

	Nine months ended September 30, 2015	
Cash provided by operating activities	$	21.9
Cash used in investing activities		(12.8)

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5. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three and nine months ended September 30, 2016 and 2015, respectively, for our equity method investments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating results	2016	2015	2016	2015
Revenue				
Chambers	$ 11.2	$ 11.0	$ 34.3	$ 37.3
Frederickson	5.8	5.8	15.7	15.9
Orlando	13.9	13.9	40.6	40.9
Other(1)	3.2	3.4	7.2	10.8
	34.1	34.1	97.8	104.9
Project expenses				
Chambers	9.3	9.2	27.8	30.2
Frederickson	4.9	5.1	14.3	14.1
Orlando	6.9	7.3	19.6	20.6
Other(1)	3.0	3.1	6.8	10.3
	24.1	24.7	68.5	75.2
Project other expense				
Chambers	(0.4)	(0.5)	(1.4)	(1.4)
Frederickson	—	—	—	—
Orlando	—	—	—	—
Other(1)	—	—	—	—
	(0.4)	(0.5)	(1.4)	(1.4)
Project income (loss)				

Chambers	$ 1.5	$ 1.3	$ 5.1	$ 5.7
Frederickson	0.9	0.7	1.4	1.8
Orlando	7.0	6.6	21.0	20.3
Other(1)	0.2	0.3	0.4	0.5
	9.6	8.9	27.9	28.3

(1) Includes equity method investments that individually do not exceed 10% of consolidated total assets or income (loss) before income taxes.

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6. Long term debt

Long term debt consists of the following:

	September 30, 2016	December 31, 2015	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2021	$ —	$ 473.2	LIBOR(1) plus 3.75 %
Senior secured term loan facility, due 2023	654.9	—	LIBOR(1) plus 5.00 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	160.1	151.7	5.95 %
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	15.0	19.5	LIBOR plus 3.125%
Cadillac term loan, due 2025	27.7	29.5	LIBOR plus 1.37 %
Piedmont term loan, due 2018	57.5	59.0	8.47 %
Other long-term debt	0.2	0.4	5.50 % - 6.70 %
Less: unamortized discount	(18.5)	—	
Less: unamortized deferred financing costs	(16.6)	(34.8)	
Less: current maturities	(101.4)	(15.8)	
Total long-term debt	$ 778.9	$ 682.7	

Current maturities consist of the following:

	September 30,	December 31,

	2016	2015	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2021	$ —	$ 4.7	LIBOR(1) plus 3.75 %
Senior secured term loan facility, due 2023(2)	90.0	—	LIBOR(1) plus 5.00 %
Epsilon Power Partners term facility, due 2019	6.1	6.0	LIBOR plus 3.125%
Cadillac term loan, due 2025	2.9	2.5	LIBOR plus 1.37 %
Piedmont term loan, due 2018	2.2	2.4	8.47 %
Other short-term debt	0.2	0.2	5.50 % - 6.70 %
Total current maturities	$ 101.4	$ 15.8	

(1) LIBOR cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $434.7 million of the $654.9 million outstanding aggregate borrowings under our senior secured term loan facility at September 30, 2016. See Note 9, Accounting for derivative instruments and hedging activities for further details.

(2) On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the credit agreement and disclosed below. 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 New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

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New Credit Facilities

On April 13, 2016, APLP Holdings Limited Partnership ("APLP Holdings"), our wholly-owned subsidiary, entered into new senior secured credit facilities, comprising $700 million in aggregate principal amount of senior secured term loan facilities (the "New Term Loans") and $200 million in aggregate principal amount of senior secured revolving credit facilities (the "New Revolver" and together with the New Term Loans, the "New Credit Facilities"). On the same date, $700 million was drawn under the New Term Loan, bearing interest at the Adjusted Eurodollar Rate plus the applicable margin of 5.00%, and letters of credit in an aggregate face amount of $105.8 million were issued (but not drawn) pursuant to the revolving commitments under the New Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $25.3 million), and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company. The New Revolver matures in April 2021 and the New Term Loans mature in April 2023. We received $679.0 million in proceeds after an original issue discount of 3% ($21.0 million).

We have used the $679.0 million proceeds from the New Term Loans to:

redeem in whole, at a price equal to par plus accrued interest, Atlantic Power Limited Partnership's ("APLP") existing senior secured term loan, maturing in February 2021, in an aggregate principal amount outstanding of $447.9 million (see "Senior Secured Credit Facilities" below);

redeem in whole, at a price equal to par plus accrued interest (i) our outstanding Cdn$67.2 million 6.25% Convertible Unsecured Subordinated Debentures, Series A, maturing in March 2017 (the "Series A Debentures") and (ii) our outstanding Cdn$75.8 million 5.60% Convertible Unsecured Subordinated Debentures, Series B, maturing in June 2017 (the "Series B Debentures") (total US$ equivalent of $110.7 million);

redeem, at a price equal to $965 per $1,000 principal amount plus accrued interest, $62.7 million of our 5.75% Convertible Unsecured Subordinated Debentures, Series C, maturing on June 30, 2019; and pay transaction costs and expenses of approximately $14.4 million.

We may use the remaining proceeds for any corporate purpose including common share repruchases.

We accounted for the redemption of the Senior Secured Credit Facilities as an extinguishment of debt and wrote off $30.2 million of deferred financing costs to interest expense in the nine months ended September 30, 2016.

Borrowings under the New Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The New Term Loans include a 3% original issue discount, and matures on April 12, 2023. The revolving commitments under the New Revolver terminate on April 12, 2021. Letters of credit are available to be issued under the New Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the New Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the New Revolver.

The New Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the “Subsidiary Guarantors”), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The New Credit Facilities also have the benefit of a debt service reserve account, which is required to be maintained at the debt service reserve requirement, equal to six months of debt service. The reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") that prohibits APLP (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the New Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 6.00:1.00 in 2016 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.75:1.00 in 2016 to 4.00:1.00 from June 30, 2022. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the New Credit Facilities, it will be required to offer each electing lender a prepayment of such lender's term loans under the New Credit Facilities at a price equal to 101% of par. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and

in respect of excess cash flow, to be determined by using the greater of (i) 50% of the cash flow of 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 New Credit Facilities and the MTNs, funding 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 New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the New Revolver), or defaults under certain guaranties and collateral documents securing the New Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

Senior Secured Credit Facilities

As noted above in “New Credit Facilities”, our Senior Secured Credit Facilities were repaid on April 13, 2016. The redemption and extinguishment was recorded in the three months ended June 30, 2016.

Notes of Atlantic Power Corporation

On July 26, 2015, we redeemed all of our outstanding $310.9 million aggregate principal amount of 9.0% Senior Unsecured Notes due November 2018 (the “Notes”) with the cash proceeds received from the sale of the Wind Projects. The Notes were redeemed at a price equal to 104.5 percent of the principal amount of the Notes, plus accrued and unpaid interest to the redemption date. We paid $330.4 million to fund the full redemption of the Notes, which includes $14.0 million in make-whole premiums and $5.5 million in accrued interest. The make whole premiums, accrued interest and the $9.0 million of deferred financing costs related to the Notes were recorded in interest expense in the three and nine months ended September 30, 2015.

Non Recourse 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 loans have certain financial covenants that must be met in order to distribute available cash to Atlantic Power. At September 30, 2016, 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 the debt is 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.

7. Convertible debentures

Convertible debentures consist of the following:

	September 30, 2016	December 31, 2015
6.25% Debentures due March 2017	$ —	$ 48.6
5.60% Debentures due June 2017	—	54.8
5.75% Debentures due June 2019	42.6	117.0
6.00% Debentures due December 2019 (Cdn$81.0 million)	61.7	65.0
Less: Unamortized deferred financing costs	(2.9)	(7.7)
Total convertible debentures	$ 101.4	$ 277.7

On November 11, 2014, we commenced a normal course issuer bid ("NCIB") for our convertible debentures. Under the NCIB, which expired on November 10, 2015, we entered into a pre-defined automatic securities purchase plan

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with our broker in order to facilitate purchases of our convertible debentures. As of December 31, 2015, we had repurchased and cancelled $24.8 million of convertible debentures and recorded a gain of $3.1 million in the consolidated statements of operations related to these transactions.

On December 29, 2015, we commenced a new NCIB, which will expire on December 28, 2016. The actual amount of convertible debentures that may be purchased under the NCIB is approximately $28.5 million and is further limited to 10% of the public float of our convertible debentures. Since inception of the NCIB in the fourth quarter of 2015 and through September 30, 2016, we repurchased and canceled $18.8 million of convertible debentures and recorded a gain of $2.5 million in the consolidated statement of operations for the nine months ended September 30, 2016.

On April 13, 2016, we deposited a portion of the proceeds from the issuance of the New Credit Facilities, for the redemption in whole on May 13, 2016 at a price equal to par plus accrued interest (i) the outstanding Cdn$67.2 million 6.25% Debentures due March 2017 and (ii) the outstanding Cdn$75.8 million 5.60% Debentures due June 2017 (total US$ equivalent of $110.7 million as of April 13, 2016). Deferred financing costs related to the debentures of $1.3 million were written off and recorded to interest expense in April 2016.

On June 17, 2016, we commenced a substantial issuer bid to purchase for cancellation up to $65.0 million aggregate principal amount of our issued and outstanding 5.75% Series C Convertible Unsecured Subordinated Debentures maturing June 30, 2019. The offer expired on July 22, 2016. An aggregate of $62.7 million principal amount of the debentures were purchased and cancelled under the offer. As of September 30, 2016, there were approximately $42.6 million principal amount of Series C debentures outstanding and a gain of $1.7 million was recorded related to the repurchase in the consolidated statements of operations for the three and nine months ended September 30, 2016. Deferred financing costs related to the debentures of $1.4 million were written off and recorded to interest expense in July 2016.

8. 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 September 30, 2016 and December 31, 2015. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	September 30, 2016			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 93.8	$ —	$ —	$ 93.8
Restricted cash	12.6	—	—	12.6
Derivative instruments asset	—	2.9	—	2.9
Total	$ 106.4	$ 2.9	$ —	$ 109.3
Liabilities:				
Derivative instruments liability	$ —	$ 42.5	$ —	$ 42.5
Total	$ —	$ 42.5	$ —	$ 42.5

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	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 72.4	$ —	$ —	$ 72.4
Restricted cash	15.2	—	—	15.2
Derivative instruments asset	—	0.3	—	0.3
Total	$ 87.6	$ 0.3	$ —	$ 87.9
Liabilities:				
Derivative instruments liability	$ —	$ 57.5	$ —	$ 57.5
Total	$ —	$ 57.5	$ —	$ 57.5

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 September 30, 2016, the credit valuation adjustments resulted in a $5.2 million net increase in fair value, which consists of a $0.5 million pre tax gain in other comprehensive income and a $4.7 million gain in change in fair value of derivative instruments. As of December 31, 2015, the credit valuation adjustments resulted in a $3.8 million net increase in fair value, which consists of a $0.4 million pre tax gain in other comprehensive income and a $3.4 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.

9. 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 agreements

Gas purchase agreements to purchase gas forward at our North Bay, Kapuskasing and Nipigon projects do not qualify for the normal purchase normal sales (“NPNS”) exemption and are accounted for as derivative financial instruments. The gas purchase agreements at North Bay and Kapuskasing satisfy all of the forecasted fuel requirements for these projects through their expiration on December 31, 2016. The gas purchase agreement for Nipigon satisfies the majority of forecasted fuel requirements through December 31, 2022. 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.

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In June 2014, 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. These contracts effectively fix the price of approximately 100% of our expected uncontracted gas requirements for 2015 and 35% and 30% of our expected uncontracted gas requirements for 2016 and 2017, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

We have entered into various natural gas sales and purchase agreements for approximately 1.3 million Mmbtu to effectively mitigate seasonal fluctuation of future natural gas price at Morris through March 2017. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at September 30, 2016. 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 5.7 million Mmbtu of future natural gas purchases at Orlando, which is approximately 95% of our share of the expected natural gas purchases at the project through December 2017. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at September 30, 2016. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

On May 5, 2014, APLP entered into several interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount ($124.7 million at September 30, 2016) of the $600 million aggregate principal amount of borrowings under the Term Loan Facility, which had entered on February 24, 2014 and redeemed in whole on May 2016. The interest rate swap agreements were effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations. These interest rate swap agreements were novated to APLP 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 $310.0 million notional amount ($124.7 million at September 30, 2016) of the $700.0 million aggregate principal amount ($654.9 million at September 30, 2016) of borrowings under the New Term Loans. Interest rate swap agreements with $160.0 million remaining notional terminate on September 30, 2019 and interest swap agreements with $150.0 million remaining notional terminate on March 31, 2020.

Borrowings under the $700.0 million New Term Loans bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 5.00%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 6.00% all-in rate on the Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $509.0 million of the New Term Loans cannot be less than 6.00%, if the Adjusted Eurodollar Rate is equal to or greater than 1.00%.

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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 agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in August 2018, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all in rate of 8.5%. The swap continues at the fixed rate of 4.47% until November 2030. Prior to conversion of the Piedmont construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. 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 6.0% through February 15, 2015, 6.1% from February 16, 2015 to 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.

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 NPNS exemption at September 30, 2016 and December 31, 2015:

	Units	September 30, 2016	December 31, 2015
Natural gas swaps	Natural Gas (Mmbtu)	4.7	2.8
Gas purchase agreements	Natural Gas (Gigajoules)	17.2	25.0
Interest rate swaps	Interest (US$)	520.4	302.3

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Fair value of derivative instruments

We have elected to 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:

	September 30, 2016	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.9
Interest rate swaps long-term	—	2.9
Total derivative instruments designated as cash flow hedges	—	3.8
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	—	2.5
Interest rate swaps long-term	0.8	10.7
Natural gas swaps current	1.5	1.0
Natural gas swaps long-term	0.5	—
Gas purchase agreements current	0.1	10.8
Gas purchase agreements long-term	—	13.7
Total derivative instruments not designated as cash flow hedges	2.9	38.7
Total derivative instruments	$ 2.9	$ 42.5

December 31, 2015

	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 1.0
Interest rate swaps long-term	—	2.7
Total derivative instruments designated as cash flow hedges	—	3.7
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	—	2.0
Interest rate swaps long-term	0.3	7.8
Natural gas swaps current	—	5.0
Natural gas swaps long-term	—	—
Gas purchase agreements current	—	28.7
Gas purchase agreements long-term	—	10.3
Total derivative instruments not designated as cash flow hedges	0.3	53.8
Total derivative instruments	$ 0.3	$ 57.5

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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 September 30, 2016	Interest Rate Swaps
Accumulated OCI balance at June 30, 2016	$ (0.1)
Change in fair value of cash flow hedges	0.0
Realized from OCI during the period	0.2
Accumulated OCI balance at September 30, 2016	$ 0.1

Three Months Ended September 30, 2015	Interest Rate Swaps
Accumulated OCI balance at June 30, 2015	$ 0.1
Change in fair value of cash flow hedges	(0.4)
Realized from OCI during the period	0.2
Accumulated OCI balance at September 30, 2015	$ (0.1)

Nine Months Ended September 30, 2016	Interest Rate Swaps
Accumulated OCI balance at January 1, 2016	$ 0.2
Change in fair value of cash flow hedges	(0.6)
Realized from OCI during the period	0.5
Accumulated OCI balance at September 30, 2016	$ 0.1

Nine Months Ended September 30, 2015	Interest Rate Swaps
Accumulated OCI balance at January 1, 2015	$ 0.1
Change in fair value of cash flow hedges	(0.8)
Realized from OCI during the period	0.6
Accumulated OCI balance at September 30, 2015	$ (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 September 30,		Nine Months Ended September 30,	
		2016	2015	2016	2015
Gas purchase agreements	Fuel	$ 12.4	$ 11.8	36.4	$ 36.1
Natural gas swaps	Fuel	0.6	1.5	4.0	4.3
Interest rate swaps	Interest, net	1.0	0.5	2.7	1.7

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

	Classification of gain (loss) recognized in income	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Natural gas swaps	Change in fair value of derivatives	$ 0.2	$ (0.1)	$ 6.0	$ 0.7
Gas purchase agreements	Change in fair value of derivatives	5.6	6.1	16.8	11.6
Interest rate swaps	Change in fair value of derivatives	3.2	(2.4)	(2.8)	(3.6)
		$ 9.0	$ 3.6	$ 20.0	$ 8.7

10. Income taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Current income tax expense (benefit)	$ 0.8	$ (1.6)	$ 2.6	$ 5.7
Deferred tax expense (benefit)	1.8	3.0	(16.8)	(6.0)
Total income tax expense (benefit), net	$ 2.6	$ 1.4	$ (14.2)	$ (0.3)

For the three and nine months ended September 30, 2016 and 2015

Income tax expense for the three months ended September 30, 2016 was $2.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $20.2 million. The primary item increasing the tax rate for the three months ended September 30, 2016 was $22.5 million related to goodwill impairment. In addition, the rate was further impacted by a net increase to our valuation allowances of $8.6 million, consisting primarily of increases of $9.3 million in Canada related to losses and a decrease of $0.7 million in the United States due to additional earnings. These items were offset by $7.2 million related to capital loss on intercompany notes, $1.9 million relating to operating in higher tax rate jurisdictions and $0.8 million of other permanent differences.

Income tax expense for the three months ended September 30, 2015 was $1.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $0.5 million. The primary items impacting the tax rate for the three months ended September 30, 2015 were $4.0 million relating to a change in valuation allowance and $2.8 million related to capital gain on repatriation of wind sale proceeds. These items were partially offset by $2.6 million of dividend withholding and other taxes, $2.2 million related to foreign exchange and $0.1 million of other permanent differences.

Income tax benefit for the nine months ended September 30, 2016 was $14.2 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $32.2 million. The primary items increasing the tax rate for the nine months ended September 30, 2016 were $22.5 million relating to goodwill impairment, $5.5 million relating to foreign exchange and $1.1 million of other permanent differences. In addition, the rate was further impacted by a net increase to the Company’s valuation allowances of $13.2 million, consisting primarily of increases of $31.6 million in Canada related to losses and a decrease of $18.4 million in the United States due to tax restructurings and additional earnings. These items were offset by $18.5 million Canadian capital losses recognized on tax restructurings, $3.0 million related to capital loss on intercompany notes and $2.8 million relating to operating in higher tax rate jurisdictions.

Income tax benefit for the nine months ended September 30, 2015 was $0.3 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.3 million. The primary items impacting the tax rate for the nine months ended September 30, 2015 were $6.3 million relating to foreign exchange, $4.0 million relating to operating in higher tax rate jurisdictions, $3.6 million related to tax credits and $0.6 million of other permanent differences. These items were partially offset by $10.1 million relating to a change in the valuation allowance, $2.8 million related to a capital gain on repatriation of wind sale proceeds and $1.0 million relating to dividend withholding and other taxes.

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As of September 30, 2016, we have recorded a valuation allowance of $188.5 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.

11. Equity compensation plans

Long term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the nine months ended September 30, 2016:

	Units	Grant Date Weighted-Average Fair Value per Unit

Outstanding at December 31, 2015	1,298,401	$	2.88
Granted	1,594,954		1.81
Vested and redeemed	(771,437)		2.85
Forfeitures	(7,431)		2.71
Outstanding at September 30, 2016	2,114,487	$	1.84

Cash payments made for vested notional units for the nine months ended September 30, 2016 and 2015 were $0.4 million and $1.0 million, respectively. Compensation expense for LTIP and Transition Equity Participation Agreement notional shares was $0.5 million and $1.4 million for the three and nine months ended September 30, 2016, respectively, and $1.0 million and $2.1 million for the three and nine months ended September 30, 2015, respectively.

Transition Equity Participation Agreement

We also have 539,904 transition notional shares outstanding at September 30, 2016 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).

12. Basic and diluted (loss) earnings per share

Basic (loss) earnings per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (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.

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

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Numerator:				
Loss from continuing operations attributable to Atlantic Power Corporation	$ (82.4)	$ (5.5)	$ (116.2)	$ (5.5)
(Loss) income from discontinued operations, net of tax	—	(0.5)	—	31.6
Net (loss) income attributable to Atlantic Power Corporation	$ (82.4)	$ (6.0)	$ (116.2)	$ 26.1
Denominator:				
Weighted average basic shares outstanding	119.3	122.1	120.9	121.8
Dilutive potential shares:				
Convertible debentures	8.1	22.4	14.9	22.8
LTIP notional units	0.1	0.1	0.1	0.1
Potentially dilutive shares	127.5	144.6	135.9	144.7
Diluted loss per share from continuing operations attributable to Atlantic Power Corporation	$ (0.69)	$ (0.05)	$ (0.96)	$ (0.05)
Diluted earnings per share from discontinued operations	—	—	—	0.26
Diluted (loss) earnings per share attributable to Atlantic Power Corporation	$ (0.69)	$ (0.05)	$ (0.96)	$ 0.21

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 $14.9 million have been excluded from fully diluted shares in the three and nine months ended September 30, 2016, respectively, because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures of $22.4 million and $22.8 million have been excluded from fully diluted shares in the three and nine months ended September 30, 2015, respectively, because their impact would be anti-dilutive.

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13. 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, noncontrolling interests and total equity for the nine months ended September 30, 2016 and 2015:

	Nine months ended September 30, 2016		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity
Balance at January 1, 2016	$ 213.9	$ 221.3	$ 435.2
Net (loss) income	(116.2)	6.4	(109.8)
Realized and unrealized loss on hedging activities, net of tax	(0.1)	—	(0.1)
Foreign currency translation adjustment	(2.6)	—	(2.6)
Common share repurchases	(13.9)	—	(13.9)
Stock-based compensation	1.4	—	1.4
Dividends declared on preferred shares of a subsidiary company	—	(6.4)	(6.4)
Balance at September 30, 2016	$ 82.5	$ 221.3	$ 303.8

Nine months ended September 30, 2015		
Total Atlantic	Preferred shares issued by a subsidiary	Noncontrolling

	Power Corporation Shareholders' Equity	company	Interests	Total Equity
Balance at January 1, 2015	$ 356.2	$ 221.3	$ 239.0	$ 816.5
Net income (loss)	26.1	6.7	(11.0)	21.8
Realized and unrealized gain on hedging activities, net of tax	(0.2)	—	—	(0.2)
Foreign currency translation adjustment	(52.7)	—	—	(52.7)
Stock-based compensation	2.1	—	—	2.1
Dividends paid to noncontrolling interest	—	—	(3.7)	(3.7)
Dividends declared on common shares	(8.5)	—	—	(8.5)
Dividends declared on preferred shares of a subsidiary company	—	(6.7)	—	(6.7)
Derecognition of noncontrolling interests upon sale of subsidiaries	—	—	(224.3)	(224.3)
Balance at September 30, 2015	$ 323.0	$ 221.3	$ —	$ 544.3

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 permits the Company to repurchase stock through open market repurchases. The NCIB will expire on December 28, 2016 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIB. For the nine months ended September 30, 2016, we repurchased a cumulative 5,678,736 common shares at a total cost of $13.9 million. Repurchases and retirement of common shares are recorded to common shares on the consolidated balance sheets. Subsequent to September 30, 2016, we repurchased an additional 1,394,096 common shares.

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14. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as the result of significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. The Wind Projects, which made up the entirety of the former Wind segment, were sold in June 2015 and are designated as discontinued operations for the three and nine months ended September 30, 2015. 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 net (loss) income from continuing operations to Project Adjusted EBITDA for the three and nine months ended September 30, 2016 and 2015 is included in the table below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended September 30, 2016					
Project revenues	$ 31.3	$ 34.1	$ 35.6	$ 0.2	$ 101.2
Segment assets	764.9	328.9	325.3	102.8	1,521.9

Project Adjusted EBITDA	$ 19.4	$ 21.3	$ 10.7	$ (0.1)	$ 51.3
Change in fair value of derivative instruments	(1.2)	—	(5.6)	(2.2)	(9.0)
Depreciation and amortization	11.0	9.9	9.4	0.1	30.4
Interest, net	2.8	—	—	—	2.8
Impairment	15.4	—	69.3	—	84.7
Other project income	—	—	—	(0.5)	(0.5)
Project (loss) income	(8.6)	11.4	(62.4)	2.5	(57.1)
Administration	—	—	—	5.7	5.7
Interest, net	—	—	—	20.0	20.0
Foreign exchange gain	—	—	—	(3.4)	(3.4)
Other income, net	—	—	—	(1.7)	(1.7)
(Loss) income from continuing operations before income taxes	(8.6)	11.4	(62.4)	(18.1)	(77.7)
Income tax expense	—	—	—	2.6	2.6
Net income (loss) from continuing operations	$ (8.6)	$ 11.4	$ (62.4)	$ (20.7)	$ (80.3)

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	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended September 30, 2015					
Project revenues	$ 38.4	$ 34.5	$ 34.4	$ 0.2	$ 107.5
Segment assets	849.7	368.2	569.5	122.8	1,910.2
Project Adjusted EBITDA	$ 27.4	$ 21.4	$ 7.6	$ (0.4)	$ 56.0
Change in fair value of derivative instruments	1.9	—	(6.1)	0.6	(3.6)
Depreciation and amortization	10.7	9.9	11.7	0.5	32.8
Interest, net	2.4	—	0.1	—	2.5
Other project expense	—	—	—	0.1	0.1
Project income (loss)	12.4	11.5	1.9	(1.6)	24.2
Administration	—	—	—	6.9	6.9
Interest, net	—	—	—	41.0	41.0
Foreign exchange gain	—	—	—	(21.7)	(21.7)
Other income, net	—	—	—	—	—
Income (loss) from continuing operations before income taxes	12.4	11.5	1.9	(27.8)	(2.0)
Income tax benefit	—	—	—	1.4	1.4
Net income (loss) from continuing operations	$ 12.4	$ 11.5	$ 1.9	$ (29.2)	$ (3.4)

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Nine Months Ended September 30, 2016					
Project revenues	$ 104.3	$ 78.7	$ 122.0	$ 0.8	$ 305.8
Segment assets	764.9	328.9	325.3	102.8	1,521.9
Project Adjusted EBITDA	$ 70.5	$ 43.4	$ 46.2	$ (0.2)	$ 159.9
Change in fair value of derivative instruments	(3.0)	—	(17.7)	0.6	(20.1)

Depreciation and amortization	33.0	29.6	27.7	0.5	90.8
Interest, net	8.2	—	—	—	8.2
Impairment	15.4	—	69.3	—	84.7
Other project income	—	—	—	(0.4)	(0.4)
Project income (loss)	16.9	13.8	(33.1)	(0.9)	(3.3)
Administration	—	—	—	17.6	17.6
Interest, net	—	—	—	87.9	87.9
Foreign exchange loss	—	—	—	19.1	19.1
Other income, net	—	—	—	(3.9)	(3.9)
Income (loss) from continuing operations before income taxes	16.9	13.8	(33.1)	(121.6)	(124.0)
Income tax benefit	—	—	—	(14.2)	(14.2)
Net income (loss) from continuing operations	$ 16.9	$ 13.8	$ (33.1)	$ (107.4)	$ (109.8)

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	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Nine Months Ended September 30, 2015					
Project revenues	$ 114.8	$ 83.9	$ 122.6	$ 0.5	$ 321.8
Segment assets	849.7	368.2	569.5	122.8	1,910.2
Project Adjusted EBITDA	$ 81.0	$ 37.1	$ 43.0	$ (2.6)	$ 158.5
Change in fair value of derivative instruments	1.6	—	(11.6)	1.3	(8.7)
Depreciation and amortization	31.8	29.7	36.5	0.9	98.9
Interest, net	7.6	—	0.1	—	7.7
Other project expense (income)	—	0.1	0.1	(2.6)	(2.4)
Project income (loss)	40.0	7.3	17.9	(2.2)	63.0
Administration	—	—	—	23.0	23.0
Interest, net	—	—	—	91.3	91.3
Foreign exchange loss	—	—	—	(49.1)	(49.1)
Other income, net	—	—	—	(3.1)	(3.1)
Income (loss) from continuing operations before income taxes	40.0	7.3	17.9	(64.3)	0.9
Income tax benefit	—	—	—	(0.3)	(0.3)
Net income (loss) from continuing operations	$ 40.0	$ 7.3	$ 17.9	$ (64.0)	$ 1.2

The table below provides information, by country, about our consolidated operations for each of the three and nine months ended September 30, 2016 and 2015 and Property, Plant & Equipment as of September 30, 2016 and December 31, 2015, 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 September 30,		Project Revenue Nine Months Ended September 30,		Property, Plant and Equipment, net of accumulated depreciation	
	2016	2015	2016	2015	September 30, 2016	December 31, 2015
United States	$ 65.6	$ 73.1	$ 183.8	$ 199.2	$ 506.1	$ 529.6
Canada	35.6	34.4	122.0	122.6	243.7	248.1
Total	$ 101.2	$ 107.5	$ 305.8	$ 321.8	$ 749.8	$ 777.7

Independent Electricity System Operator (“IESO”), San Diego Gas & Electric, Georgia Power Company and BC Hydro provided 24.5%, 16.1%, 10.9%, and 10.6%, respectively, of total consolidated revenues for the three months ended September 30, 2016. IESO, BC Hydro and San Diego Gas & Electric provided 28.0%, 11.6% and 11.5% respectively, of total consolidated revenues for the nine months ended September 30, 2016. IESO, San Diego Gas & Electric, Georgia Power and BC Hydro provided 22.9%, 16.7%, 10.2% and 9.1%, respectively, of total consolidated revenues for the three months ended September 30, 2015 and 27.7%, 12.6%, 10.4% and 7.7%, respectively, of total consolidated revenues for the nine months ended September 30, 2015. IESO purchases 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, Georgia Power purchases electricity from the Piedmont 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.

15. 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

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.

16. Contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of September 30, 2016.

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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 plan, including the objective of enhancing the value of our existing assets through optimization investments and commercial activities, delevering our balance sheet to improve our cost of capital, improving our cost structure and reducing overhead;

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

· our ability to meet the financial covenants under our New Credit Facilities 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, 2015 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, 2015 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:

· 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 New Credit Facilities;

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- 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 expiration or termination of power purchase agreements and our ability to renew or enter into new power purchase agreements on favorable terms or at all;
- 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;
- our ability to retain, motivate and recruit executives and other key employees; and
- our ability to remediate the reported material weakness in our internal control over financial reporting.

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 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.

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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 power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of September 30, 2016, our power generation projects in operation 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 operational power generation projects across nine states in the United States and two provinces in Canada. Eighteen of our projects are majority owned subsidiaries.

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, and approximately 25% of our PPAs on a MW weighted basis are scheduled to expire over the next four years. 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 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

Substantial Issuer Bid

On June 17, 2016, we commenced a substantial issuer bid to purchase for cancellation up to $65.0 million aggregate principal amount of our issued and outstanding 5.75% Series C Convertible Unsecured Subordinated Debentures maturing June 30, 2019. The offer expired on July 22, 2016. An aggregate of $62.7 million principal amount of the debentures were purchased and cancelled under the offer. As of September 30, 2016 there were approximately $42.6 million principal amount of Series C debentures outstanding. We recorded a gain of approximately $1.7 million related to the repurchase in the consolidated statement of operations for the three and nine months ended September 30, 2016. Deferred financing costs related to the debentures of $1.4 million were written off and recorded to interest expense in July 2016.

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Common share repurchases

During the third quarter of 2016, we purchased and cancelled, pursuant to our normal course issuer bid, 3.7 million common shares at a cost of $9.1 million with a portion of the proceeds from the New Credit Facilities. During the first nine months of 2016, we purchased and cancelled a total of approximately 5.7 million shares at a cost of $13.9 million. Subsequent to September 30, 2016, we purchased an additional 1.4 million common shares, bringing the total repurchases to 7.1 million shares during 2016 at a cost of $17.3 million.

Impairment of long-lived assets and goodwill

In the third quarter of 2016, we recorded full goodwill impairments at our Mamquam, North Bay and Kapuskasing reporting units and a partial goodwill impairment at our Curtis Palmer reporting unit totaling $78.8 million. Additionally, we recorded long-lived asset impairments at our North Bay and Kapuskasing reporting units totaling $5.9 million. See Note 3, Goodwill, to our Quarterly Report on Form 10-Q for the three and nine months ended September 30, 2016 for a full description of our impairment analysis.

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OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of November 4, 2016, 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
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	December 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	December 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(4)	New York	Hydro	60	100.00	%	60	Niagara Mohawk Power Corporation	December 2027
Selkirk(1)	New York	Natural Gas	345	17.70	%	61	Merchant	N/A

West U.S. Segment								
Naval Station	California	Natural Gas	47	100.00	%	47	San Diego Gas & Electric(5)	December 2019
Naval Training Center	California	Natural Gas	25	100.00	%	25	San Diego Gas & Electric(5)	December 2019
North Island	California	Natural Gas	40	100.00	%	40	San Diego Gas & Electric(5)	December 2019
Oxnard	California	Natural Gas	49	100.00	%	49	Southern California Edison	May, 2020
Manchief	Colorado	Natural Gas	300	100.00	%	300	Public Service Company of Colorado	April, 2022
Frederickson(1)	Washington	Natural Gas	250	50.15	%	50	Benton Co. PUD	August, 2022
						45	Grays Harbor PUD	August, 2022
						30	Franklin, Co. PUD	August, 2022
Koma Kulshan(1)	Washington	Hydro	13	49.80	%	6	Puget Sound Energy	December 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	Independent Electricity System Operator	June, 2020
Kapuskasing	Ontario	Natural Gas	40	100.00	%	40	Independent Electricity System Operator	December 2017
Nipigon	Ontario	Natural Gas	40	100.00	%	40	Independent Electricity System Operator	December 2022
North Bay	Ontario	Natural Gas	40	100.00	%	40	Independent Electricity System Operator	December 2017
Tunis(6)	Ontario	Natural Gas	40	100.00	%	40	Independent Electricity System Operator	NA

(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 September 30, 2016, the facility has generated 6,899 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

(5) Our land leases with the U.S. Navy expire in February 2018 along with the associated energy sales agreements. We have initiated communications with the U.S. Navy to extend the leases through at least the expiration date of the PPAs in December 2019.

(6) On January 20, 2015, we entered into an agreement with the Ontario Power Authority and its successor, the Independent Electricity System Operator ("IESO"), for the future operations of the Tunis facility. Subject to meeting certain technical modifications to the plant, gas delivery and other requirements, Tunis will operate under a 15 year agreement with the IESO commencing between November 2017 and June 2019. The new contract will require the plant to become fully dispatchable as opposed to its current baseload configuration. As such, Tunis will provide electricity to the Ontario grid only when required, thereby assisting to reduce the incidents of surplus baseload generation in the market. 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 is called upon to operate.

Consolidated Overview and Results of Operations

Performance highlights

The following table provides a summary of our consolidated results of operations for the three and nine months ended September 30, 2016 and 2015, which are analyzed in greater detail below:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Project revenue	$ 101.2	$ 107.5	$ 305.8	$ 321.8

Project (loss) income	$ (57.1)	$ 24.2	$ (3.3)	$ 63.0
(Loss) income from continuing operations	$ (80.3)	$ (3.4)	$ (109.8)	$ 1.2
Income from discontinued operations	$ —	$ (0.5)	$ —	$ 20.6
Net (loss) income attributable to Atlantic Power Corporation	$ (82.4)	$ (6.0)	$ (116.2)	$ 26.1
Loss per share from continuing operations attributable to Atlantic Power Corporation—basic and diluted	$ (0.69)	$ (0.05)	$ (0.96)	$ (0.05)
Earnings per share from discontinued operations—basic and diluted	—	—	—	0.26
(Loss) earnings per share attributable to Atlantic Power Corporation—basic and diluted	$ (0.69)	$ (0.05)	$ (0.96)	$ 0.21
Project Adjusted EBITDA(1)	$ 51.3	$ 56.0	$ 159.9	$ 158.5

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

Revenue decreased by $6.3 million from $107.5 million in the three months ended September 30, 2015 to $101.2 million in the three months ended September 30, 2016. The primary drivers of the decrease are as follows:

- Impact of the Morris maintenance outage – our Morris project underwent a planned gas turbine overhaul in August 2016 resulting in $4.8 million lower revenue from the comparable 2015 period; and

- Hydrological conditions – we recorded a $2.0 million decrease in revenue due to lower water flows at our Curtis Palmer hydro project, which is located in New York, than the comparable 2015 period. This was

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partially offset by $1.1 million of increased revenues from higher water flows at our Mamquam and Moresby Lake hydro projects, which are located in British Columbia, Canada.

Consolidated project income decreased by $81.3 million from $24.2 million project income in the three months ended September 30, 2015 to $57.1 million project loss in the three months ended September 30, 2016. The primary drivers of the decrease are as follows:

- Impairment of goodwill and long-lived assets – we recorded an $84.7 million goodwill and long-lived asset impairment in the third quarter of 2016. See Note 3, Goodwill, for full detail of the conditions that resulted in recording the impairment;

- Revenue – revenue decreased $6.3 million as discussed above.

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

- Interest rate swaps and fuel derivatives – the change in fair value of derivatives increased $5.4 million from the comparable 2015 period due primarily to higher interest rates and the approaching expiration date of December 31, 2016 for out-of-the money fuel purchase agreements at our North Bay and Kapuskasing projects;

- Fuel expense – fuel expense decreased $4.3 million from the comparable 2015 period primarily due to the Morris maintenance outage described above, as well as lower natural gas prices; and

- Depreciation expense – depreciation expense decreased $2.5 million from the comparable 2015 period primarily due to a $2.4 million decrease at our Williams Lake project. We recorded a $74.1 million long-lived asset impairment at Williams Lake in the fourth quarter of 2015, which results in lower depreciation expense in the current nine month period.

Revenue decreased by $16.0 million from $321.8 million in the nine months ended September 30, 2015 to $305.8 million in the nine months ended September 30, 2016. The primary drivers of the decrease are as follows:

- Impact of lower fuel costs – energy revenue pricing at several of our projects is impacted by changes in fuel cost. Lower fuel prices during 2016 resulted in a $12.5 million decrease in revenue from 2015. These decreases in revenue are offset by lower fuel expense so the net impact on project income is not material;

- Impact of the Morris maintenance outage – our Morris project underwent a planned gas turbine overhaul in August 2016 resulting in $4.8 million lower revenue from the comparable 2015 period; and

- Currency – an approximate $6.8 million impact at our Canadian projects resulting from fluctuations of the Canadian Dollar against the U.S. dollar. The decrease in revenue due to currency is partially offset by the benefit of lower expenses also from currency at our Canadian projects. Currency had a net positive impact of $0.7 million on consolidated project income relative to the comparable 2015 period.

These decreases were partially offset by:

- Hydrological conditions – a $3.5 million increase in revenue from higher water flows at our hydro projects.

Consolidated project (loss) income decreased by $66.4 million from $63.0 million of income for the nine months ended September 30, 2015 to a loss of $(3.3) million in the nine months ended September 30, 2016. The primary drivers of the change are as follows:

- Impairment of goodwill and long-lived assets – we recorded an $84.7 million goodwill and long-lived asset impairment in the third quarter of 2016. See Note 3, Goodwill, for full detail of the conditions that resulted in recording the impairment; and

- Revenue – revenue decreased $16.0 million as discussed above.

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

· Fuel expense – fuel expense decreased from $125.3 million in the nine months ended September 30, 2015 to $110.8 million in the nine months ended September 30, 2016 primarily due to the Morris outage, foreign currency exchange rate fluctuations and lower natural gas prices;

· Fuel swap and natural gas purchases – the change in fair value of derivatives increased $11.3 million from the comparable 2015 period due primarily to higher interest rates and the approaching expiration date of December 31, 2016 for out-of-the money fuel purchase agreements at our North Bay and Kapuskasing projects; and

· Depreciation and amortization – depreciation and amortization decreased $8.2 million from the comparable 2015 period due to lower property, plant and equipment resulting from an $80.5 million long-lived asset impairment recorded in the fourth quarter of 2015.

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 53.

We have four reportable segments: East U.S., West U.S., Canada and Un Allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. The Wind Projects, which made up the entirety of the former Wind segment, were sold in June 2015 and are designated as discontinued operations for the three and nine months ended September 30, 2015. 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 September 30, 2016 compared to the three months ended September 30, 2015

The following table provides our consolidated results of operations:

	Three months ended September 30,				
	2016	2015	$ change	% change	
Project revenue:					
Energy sales	$ 40.7	$ 43.4	$ (2.7)	(6.2)	%
Energy capacity revenue	44.0	45.9	(1.9)	(4.1)	%
Other	16.5	18.2	(1.7)	(9.3)	%
	101.2	107.5	(6.3)	(5.9)	%
Project expenses:					
Fuel	36.8	41.1	(4.3)	(10.5)	%
Operations and maintenance	28.2	24.8	3.4	13.7	%
Depreciation and amortization	25.3	27.8	(2.5)	(9.0)	%
	90.3	93.7	(3.4)	(3.6)	%
Project other income (expense):					
Change in fair value of derivative instruments	9.0	3.6	5.4	150.0	%
Equity in earnings of unconsolidated affiliates	9.6	8.9	0.7	7.9	%
Interest expense, net	(2.4)	(2.1)	(0.3)	14.3	%
Impairment	(84.7)	—	(84.7)	(100.0)	%
Other income, net	0.5	—	0.5	100.0	%
	(68.0)	10.4	(78.4)	(753.8)	%
Project (loss) income	(57.1)	24.2	(81.3)	(336.0)	%
Administrative and other expenses (income):					
Administration	5.7	6.9	(1.2)	(17.4)	%
Interest, net	20.0	41.0	(21.0)	(51.2)	%
Foreign exchange gain	(3.4)	(21.7)	18.3	(84.3)	%
Other income, net	(1.7)	—	(1.7)	(100.0)	%
	20.6	26.2	(5.6)	(21.4)	%
Loss from continuing operations before income taxes	(77.7)	(2.0)	(75.7)	NM	
Income tax expense	2.6	1.4	1.2	NM	
Loss from continuing operations	(80.3)	(3.4)	(76.9)	NM	
Loss from discontinued operations, net of tax	—	(0.5)	0.5	(100.0)	%
Net loss	(80.3)	(3.9)	(76.4)	NM	
Net income attributable to Preferred share dividends of a subsidiary company	2.1	2.1	—	0.0	%
Net loss attributable to Atlantic Power Corporation	$ (82.4)	$ (6.0)	$ (76.4)	NM	

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	Three months ended September 30, 2016				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 13.9	$ 9.5	$ 17.3	$ —	$ 40.7
Energy capacity revenue	15.0	19.0	10.0	—	44.0
Other	2.4	5.6	8.3	0.2	16.5
	31.3	34.1	35.6	0.2	101.2
Project expenses:					
Fuel	9.6	10.5	16.7	—	36.8
Operations and maintenance	14.2	5.5	8.2	0.3	28.2
Depreciation and amortization	8.5	7.3	9.4	0.1	25.3
	32.3	23.3	34.3	0.4	90.3
Project other income (expense):					
Change in fair value of derivative instruments	1.2	—	5.6	2.2	9.0
Equity in earnings of unconsolidated affiliates	9.0	0.6	—	—	9.6
Interest expense, net	(2.4)	—	—	—	(2.4)
Impairment	(15.4)	—	(69.3)	—	(84.7)
Other income, net	—	—	—	0.5	0.5
	(7.6)	0.6	(63.7)	2.7	(68.0)
Project (loss) income	$ (8.6)	$ 11.4	$ (62.4)	$ 2.5	$ (57.1)

	Three months ended September 30, 2015				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total (1)
Project revenue:					
Energy sales	$ 17.4	$ 10.0	$ 16.0	$ —	$ 43.4
Energy capacity revenue	16.8	19.0	10.1	—	45.9
Other	4.2	5.6	8.2	0.2	18.2
	38.4	34.6	34.3	0.2	107.5
Project expenses:					
Fuel	14.5	10.8	15.8	—	41.1
Operations and maintenance	7.4	5.8	11.0	0.6	24.8
Development	—	—	—	—	—
Depreciation and amortization	8.4	7.2	11.7	0.5	27.8
	30.3	23.8	38.5	1.1	93.7
Project other income (expense):					
Change in fair value of derivative instruments	(1.9)	—	6.1	(0.6)	3.6

Equity in earnings of unconsolidated affiliates	8.2	0.7	—	—	8.9
Interest expense, net	(2.0)	—	—	(0.1)	(2.1)
Other expense, net	—	—	—	—	—
	4.3	0.7	6.1	(0.7)	10.4
Project income (loss)	$ 12.4	$ 11.5	$ 1.9	$ (1.6)	$ 24.2

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended September 30, 2015. The Wind Projects were sold in June 2015.

East U.S.

Project income for the three months ended September 30, 2016 decreased $21.0 million from the comparable 2015 period primarily due to:

- decreased project income of $17.5 million at Curtis Palmer primarily due to a $15.4 million goodwill impairment charge and $1.9 million in decreased revenues due to lower water flows from the comparable 2015 period; and

- decreased project income of $8.6 million at Morris primarily due to $7.1 million of increased maintenance

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expense resulting from the overhaul of two gas turbines and one steam turbine in August 2016 as well as replacement of a continuous emissions monitoring system.

These decreases were partially offset by:

- Increased project income of $2.5 million at Piedmont primarily due to a $2.7 million increase in change in fair value of derivatives.

West U.S.

Project income for the three months ended September 30, 2016 did not change materially from the comparable 2015 period.

Canada

Project income for the three months ended September 30, 2016 decreased $64.3 million from the comparable 2015 period primarily due to:

- decreased project income of $48.6 million at Mamquam, which recorded a $50.2 million goodwill impairment charge, partially offset by $1.1 million of increased revenue from higher water flows than the comparable 2015 period;

- decreased project income of $8.7 million at North Bay primarily due to $10.2 million of goodwill and long-lived asset impairments, partially offset by a $1.2 million decrease in operation and maintenance costs. North Bay underwent a maintenance outage in the comparable 2015 period; and

- decreased project income of $7.0 million at Kapuskasing primarily due to $8.9 million of goodwill and long-lived asset impairments, partially offset by a $1.3 million decrease in operation and maintenance cost. Kapuskasing underwent a maintenance outage in the comparable 2015 period.

Un allocated Corporate

Total project income for the three months ended September 30, 2016 was $2.5 million compared to a total project loss of $1.6 million in the comparable 2015 period primarily due to a $2.8 million increase in the fair value of interest rate swap agreements.

Administrative and other expenses (income)

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

Administration

Administration expense decreased $1.2 million or 17.4% from the comparable 2015 period primarily due to a $0.6 million decrease in professional services expense, a $0.3 million decrease in compensation costs and a $0.3 million decrease in rent expense.

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Interest, net

Interest expense decreased $21.0 million or 51.2% from the comparable 2015 period primarily due to purchases and cancellation of 5.75% Series C convertible debentures under our substantial issuer bid and the redemption of the 9.0% Notes in July 2015.

Foreign exchange loss (gain)

Foreign exchange gain for the three months ended September 30, 2016 decreased $18.3 million, or 84.3%, from the comparable 2015 period primarily due to an $18.3 million decrease in unrealized gain in the revaluation of instruments denominated in Canadian dollars. The repurchase of $116.8 million of Canadian Dollar denominated convertible debentures was the most significant factor in the decrease. The closing U.S. dollar to Canadian dollar exchange rates were 1.31 and 1.29 at September 30, 2016 and June 30, 2016, respectively, an increase of 1.5%. The closing U.S. dollar to Canadian dollar exchange rates were 1.34 and 1.25 at September 30, 2015 and June 30, 2015, respectively, an increase of 7.2%. The average U.S. dollar to Canadian dollar exchange rates were 1.31 and 1.31 for the three months ended September 30, 2016 and 2015, respectively.

Other income, net

Other income, net increased $1.7 million primarily due to a $1.7 million gain recorded on the purchase and cancellation of convertible debentures under the substantial issuer bid.

Income tax expense

Income tax expense for the three months ended September 30, 2016 was $2.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $20.2 million. The primary item increasing the tax rate for the three months ended September 30, 2016 was $22.5 million relating to goodwill impairment. In addition, the rate was further impacted by a net increase to our valuation allowances of $8.6 million, consisting primarily of increases of $9.3 million in Canada related to losses and a decrease of $0.7 million in the United States due to additional earnings. These items were offset by $7.2 million related to capital loss on intercompany notes, $1.9 million relating to operating in higher tax rate jurisdictions and $0.8 million of other permanent differences.

Income tax expense for the three months ended September 30, 2015 was $1.4 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.5 million. The primary items impacting the tax rate for the three months ended September 30, 2015 were $4.0 million relating to a change in the valuation allowance and $2.8 million related to capital gain on repatriation of wind sale proceeds. These items were partially offset by $2.6 million of dividend withholding and other taxes, $2.2 million related to foreign exchange and $0.1 million of other permanent differences.

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Nine months ended September 30, 2016 compared to the nine months ended September 30, 2015

The following table provides our consolidated results of operations:

	Nine months ended September 30,				
	2016	2015	$ change	% change	
Project revenue:					
Energy sales	$ 138.4	$ 144.9	$ (6.5)	(4.5)	%
Energy capacity revenue	113.2	117.4	(4.2)	(3.6)	%
Other	54.2	59.5	(5.3)	(8.9)	%
	305.8	321.8	(16.0)	(5.0)	%
Project expenses:					
Fuel	110.8	125.3	(14.5)	(11.6)	%
Operations and maintenance	79.4	81.6	(2.2)	(2.7)	%
Development	—	1.1	(1.1)	(100.0)	%
Depreciation and amortization	75.6	83.8	(8.2)	(9.8)	%
	265.8	291.8	(26.0)	(8.9)	%
Project other income (expense):					
Change in fair value of derivative instruments	20.0	8.7	11.3	129.9	%
Equity in earnings of unconsolidated affiliates	27.9	28.3	(0.4)	(1.4)	%
Interest expense, net	(6.9)	(6.2)	(0.7)	11.3	%
Impairment	(84.7)	—	(84.7)	(100.0)	%
Other income, net	0.4	2.2	(1.8)	(81.8)	%
	(43.3)	33.0	(76.3)	(231.2)	%
Project (loss) income	(3.3)	63.0	(66.3)	(105.2)	%
Administrative and other expenses (income):					
Administration	17.6	23.0	(5.4)	(23.5)	%
Interest, net	87.9	91.3	(3.4)	(3.7)	%
Foreign exchange loss (gain)	19.1	(49.1)	68.2	(138.9)	%
Other income, net	(3.9)	(3.1)	(0.8)	25.8	%
	120.7	62.1	58.6	94.4	%
(Loss) income from continuing operations before income taxes	(124.0)	0.9	(124.9)	NM	
Income tax benefit	(14.2)	(0.3)	(13.9)	NM	
(Loss) income from continuing operations	(109.8)	1.2	(111.0)	NM	
Income from discontinued operations, net of tax	—	20.6	(20.6)	(100.0)	%
Net (loss) income	(109.8)	21.8	(131.6)	NM	
Net loss attributable to noncontrolling interests	—	(11.0)	11.0	(100.0)	%
Net income attributable to Preferred share dividends of a subsidiary company	6.4	6.7	(0.3)	(4.5)	%
Net (loss) income attributable to Atlantic Power Corporation	$ (116.2)	$ 26.1	$ (142.3)	NM	

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	Nine months ended September 30, 2016				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 53.8	$ 23.6	$ 61.0	$ —	$ 138.4
Energy capacity revenue	39.8	38.9	34.5	—	113.2
Other	10.7	16.2	26.5	0.8	54.2
	104.3	78.7	122.0	0.8	305.8
Project expenses:					
Fuel	35.4	26.4	49.0	—	110.8
Operations and maintenance	33.2	18.5	26.6	1.1	79.4
Depreciation and amortization	25.5	21.9	27.8	0.4	75.6
	94.1	66.8	103.4	1.5	265.8
Project other income (expense):					
Change in fair value of derivative instruments	3.0	—	17.6	(0.6)	20.0
Equity in earnings of unconsolidated affiliates	26.0	1.9	—	—	27.9
Interest expense, net	(6.9)	—	—	—	(6.9)
Impairment	(15.4)	—	(69.3)	—	(84.7)
Other income, net	—	—	—	0.4	0.4
	6.7	1.9	(51.7)	(0.2)	(43.3)
Project income (loss)	$ 16.9	$ 13.8	$ (33.1)	$ (0.9)	$ (3.3)

	Nine months ended September 30, 2015				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total (1)
Project revenue:					
Energy sales	$ 57.3	$ 28.8	$ 58.8	$ —	$ 144.9
Energy capacity revenue	43.1	38.7	35.6	—	117.4
Other	14.4	16.3	28.3	0.5	59.5
	114.8	83.8	122.7	0.5	321.8
Project expenses:					
Fuel	44.5	30.3	50.5	—	125.3
Operations and maintenance	24.1	26.2	29.2	2.1	81.6
Development	—	—	—	1.1	1.1
Depreciation and amortization	24.6	21.8	36.5	0.9	83.8
	93.2	78.3	116.2	4.1	291.8
Project other income (expense):					
Change in fair value of derivative instruments	(1.6)	—	11.6	(1.3)	8.7
Equity in earnings of unconsolidated affiliates	26.3	1.8	—	0.2	28.3
Interest expense, net	(6.2)	—	—	—	(6.2)
Other (expense) income, net	(0.1)	—	(0.2)	2.5	2.2

	18.4	1.8	11.4	1.4	33.0
Project income (loss)	$ 40.0	$ 7.3	$ 17.9	$ (2.2)	$ 63.0

(1) Excludes the Wind Projects, which were designated as discontinued operations for the nine months ended September 30, 2015. The Wind Projects were sold in June 2015.

East U.S.

Project income for the nine months ended September 30, 2016 decreased $23.1 million from the comparable 2015 period primarily due to:

· decreased project income of $15.6 million at Curtis Palmer due to a $15.4 million goodwill impairment charge recorded; and

· decreased project income of $11.1 million at Morris primarily due to $8.1 million of increased maintenance expense resulting from the overhaul of two gas turbines and one steam turbine in August 2016. Morris also

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recorded $1.0 million of higher depreciation expense than the comparable period related to new capital expenditures.

West U.S.

Project income for the nine months ended September 30, 2016 increased $6.5 million from the comparable 2015 period primarily due to:

- increased project income of $7.5 million at Manchief primarily due to $8.2 million of decreased maintenance expense, partially offset by a $0.7 million of decreased revenue resulting from lower dispatch.

This increase was partially offset by:

- decreased project income of $0.6 million at Naval Station primarily due to a hot gas path maintenance outage.

Canada

Project income for the nine months ended September 30, 2016 decreased $51.0 million from the comparable 2015 period primarily due to:

- decreased project income of $45.7 million at Mamquam primarily due to a $50.2 million goodwill impairment, partially offset by a $3.4 million increase in energy revenue due to higher water flows than the comparable period in 2015 and a $1.2 million decrease in operation and maintenance expense due to a maintenance outage in the comparable 2015 period;

- decreased project income of $7.0 million at North Bay primarily due to $10.2 million of goodwill and long-lived asset impairments, partially offset by a $2.8 million change in the fair value of gas purchase agreements that are accounted for as derivatives; and

- decreased project income of $5.8 million at Kapuskasing primarily due to $8.9 million of goodwill and long-lived asset impairments, partially offset by a $2.8 million change in the fair value of gas purchase agreements that are accounted for as derivatives.

These decreases were partially offset by:

· increased project income of $7.2 million at Williams Lake primarily due to a $7.8 million decrease in depreciation expense resulting from a $74.1 million long-lived asset impairment recorded in the fourth quarter of December 31, 2015.

Un allocated Corporate

Project loss for the nine months ended September 30, 2016 decreased by $1.3 million from the comparable 2015 period primarily due to a $0.7 million decrease in change in fair value of interest rate swap agreement, partially offset by $2.3 million gain recorded in the comparable 2015 period for the sale of the Frontier solar development project.

Administrative and other expenses (income)

Administration

Administration expense decreased $5.4 million or 24% from the comparable 2015 period primarily due to a $2.3 million decrease in employee compensation expense, a $1.6 million decrease in professional services and a $1.4 million decrease in rent expense.

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Interest, net

Interest expense decreased $3.4 million or 3.7% from the comparable 2015 period primarily due to lower interest expense from the 9.0 % Notes, which were redeemed in the comparable 2015 period, as well as lower interest expense from our convertible debentures, which have been repurchased and cancelled, in part, during 2015 and 2016. This is partially offset by higher interest expense related to the write-off of deferred financing costs of the previous term loan facility and convertible debentures during 2016, as compared to interest expense recorded for make-whole payments and deferred financing costs write-offs related to the 9.0% Notes recorded in the comparable 2015 period.

Foreign exchange loss (gain)

Foreign exchange loss was $19.1 million for the nine months ended September 30, 2016, compared to a $49.1 million gain for the nine months ended September 30, 2015, a change of $68.2 million. The decrease was primarily due to a $68.4 million decrease in unrealized gain on the revaluation of instruments denominated in Canadian dollars. The repurchase of $116.8 million of Canadian Dollar denominated convertible debentures was the most significant factor in the decrease of that unrealized revaluation gain. The closing U.S. dollar to Canadian dollar exchange rates were 1.31 and 1.38 at September 30, 2016 and December 31, 2015, respectively, a decrease of 5.2%. The closing U.S. dollar to Canadian dollar exchange rates were 1.34 and 1.16 at September 30, 2015 and December 31, 2014, respectively, an increase of 15.0%. The average U.S. dollar to Canadian dollar exchange rates were 1.34 and 1.25 for the nine months ended September 30, 2016 and 2015, respectively.

Income tax expense

Income tax benefit for the nine months ended September 30, 2016 was $14.2 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $32.2 million. The primary items increasing the tax rate for the nine months ended September 30, 2016 were $22.5 million relating to goodwill impairment, $5.5 million relating to foreign exchange and $1.1 million of other permanent differences. In addition, the rate was further impacted by a net increase to the Company’s valuation allowances of $13.2 million, consisting primarily of increases of $31.6 million in Canada related to losses and a decrease of $18.4 million in the United States due to tax restructurings and additional earnings. These items were offset by $18.5 million Canadian capital losses recognized on tax restructurings, $3.0 million related to capital loss on intercompany notes and $2.8 million relating to operating in higher tax rate jurisdictions.

Income tax benefit for the nine months ended September 30, 2015 was $0.3 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.3 million. The primary items impacting the tax rate for the nine months ended September 30, 2015 were $6.3 million relating to foreign exchange, $4.0 million relating to operating in higher tax rate jurisdictions, $3.6 million related to tax credits and $0.6 million of other permanent differences. These items were partially offset by $10.1 million relating to a change in the valuation allowance, $2.8 million related to a capital gain on repatriation of wind sale proceeds and $1.0 million relating to dividend withholding and other taxes.

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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. 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 nine months ended September 30, 2016. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in thousands of Net MWh.

	Generation(1)			
	Three months ended September 30,			
(in thousands of Net MWh)	2016	2015	% change 2016 vs. 2015	
Segment				
East U.S.	570.6	663.0	(13.9)	%
West U.S.	522.9	583.3	(10.4)	%
Canada	446.7	420.4	6.3	%
Total	1,540.2	1,666.7	(7.6)	%

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended September 30, 2015. The Wind Projects were sold in June 2015.

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Aggregate power generation for the three months ended September 30, 2016 decreased 7.6% from the comparable 2015 period primarily due to:

- decreased generation in the East U.S. segment primarily due to a 81.8 net MWh decrease in generation at Morris due to a maintenance outage in the third quarter of 2016 and a 16.6 net MWh decrease in generation at Curtis Palmer due to lower water flow than the comparable 2015 period; and

- decreased generation in the West U.S. segment primarily due to a 38.6 net MWh decrease in generation at Frederickson due to lower dispatch resulting from higher availability of hydro plants in the region and a maintenance outage in September 2016.

These decreases were partially offset by:

- increased generation in the Canada segment primarily due to a 28.7 net MWh increase in generation at Mamquam, which underwent a maintenance outage in the comparable 2015 period.

	Generation(1)			
	Nine months ended September 30,			
			% change	
(in thousands of Net MWh)	2016	2015	2016 vs. 2015	
Segment				
East U.S.	1,848.7	1,962.3	(5.8)	%
West U.S.	1,225.6	1,350.6	(9.3)	%
Canada	1,491.5	1,394.2	7.0	%
Total	4,565.8	4,707.1	(3.0)	%

(1) Excludes the Wind Projects, which were designated discontinued operations for the three and nine months ended September 30, 2015. The Wind Projects were sold in June 2015.

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Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Aggregate power generation for the nine months ended September 30, 2016 decreased 3.0% from the comparable 2015 period primarily due to:

- decreased generation in the East U.S. segment primarily due to a 59.7 net MWh decrease in generation at Selkirk due to lower dispatch, a 47.5 net MWh decrease in generation at Morris due to a maintenance outage in the third quarter of 2016, and a 43.4 net MWh decrease in generation at Chambers due to a maintenance outage in the second quarter of 2016; and

- decreased generation in the West U.S. segment primarily due to a 91.7 net MWh decrease in generation at Manchief due to lower dispatch.

These decreases were partially offset by:

- increased generation in the Canada segment primarily due to a 100.1 net MWh increase in generation at Mamquam, which underwent a maintenance outage in the comparable 2015 period.

	Availability(1) Three months ended September 30,					
	2016		2015		% change 2016 vs. 2015	
Segment						
East U.S.	88.2	%	97.4	%	(9.2)	%
West U.S.	96.9	%	98.1	%	(1.2)	%
Canada	90.6	%	91.0	%	(0.4)	%
Weighted average	91.1	%	96.2	%	(5.1)	%

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three months ended September 30, 2015. The Wind Projects were sold in June 2015.

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Weighted average availability for the three months ended September 30, 2016 decreased 5.1% from the comparable 2015 period primarily due to:

- decreased availability in the East U.S. segment resulting from decreased availability at Morris due to a maintenance outage in the third quarter of 2016. This was partially offset by increased availability at Piedmont, which had lower outage hours than the comparable 2015 period;

- decreased availability in the West U.S. segment resulting from decreased availability at Naval Training Center due to a maintenance outage in the third quarter of 2016 and at Naval Station due to a replacement of steam turbine parts; and

- decreased availability in the Canada segment resulting from decreased availability at Calstock due to a maintenance outage in September 2016. This was partially offset by increased availability at Mamquam, which underwent a maintenance outage in the comparable 2015 period.

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	Availability(1) Nine months ended September 30,					
	2016		2015		% change 2016 vs. 2015	
Segment						
East U.S.	93.3	%	96.6	%	(3.3)	%
West U.S.	92.4	%	92.4	%	—	%
Canada	95.5	%	94.0	%	1.5	%
Weighted average	93.5	%	94.9	%	(1.4)	%

(1) Excludes the Wind Projects, which were designated as discontinued operations for the three and nine months ended September 30, 2015. The Wind Projects were sold in June 2015.

Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Weighted average availability for the nine months ended September 30, 2016 decreased 1.4% from the comparable 2015 period primarily due to:

- decreased availability in the East U.S. segment resulting from decreased availability at Morris due to a maintenance outage in the third quarter of 2016.

This decrease was partially offset by:

- increased availability in the Canada segment resulting from increased availability at Mamquam, which underwent an outage during the comparable period in 2015.

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.

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Project Adjusted EBITDA

	Three months ended September 30, 2016	2015	$ change 2016 vs 2015	Nine months ended September 30, 2016	2015	$ change 2016 vs 2015
Net (loss) income	$ (80.3)	$ (3.9)	$ (76.4)	$ (109.8)	$ 21.8	$ (131.6)
Net Income from discontinued operations, net of tax	—	(0.5)	0.5	—	20.6	(20.6)
Income tax expense (benefit)	2.6	1.4	1.2	(14.2)	(0.3)	(13.9)
(Loss) income from continuing operations before income taxes	(77.7)	(2.0)	(75.7)	(124.0)	0.9	(124.9)
Administration	5.7	6.9	(1.2)	17.6	23.0	(5.4)
Interest, net	20.0	41.0	(21.0)	87.9	91.3	(3.4)
Foreign exchange loss (gain)	(3.4)	(21.7)	18.3	19.1	(49.1)	68.2
Other income, net	(1.7)	—	(1.7)	(3.9)	(3.1)	(0.8)
Project (loss) income	$ (57.1)	$ 24.2	$ (81.3)	$ (3.3)	$ 63.0	$ (66.3)
Reconciliation to Project Adjusted EBITDA						
Depreciation and amortization	30.4	32.8	(2.4)	90.8	98.9	(8.1)
Interest expense, net	2.8	2.5	0.3	8.2	7.7	0.5
Change in the fair value of derivative instruments	(9.0)	(3.6)	(5.4)	(20.1)	(8.7)	(11.4)
Impairment	84.7	—	84.7	84.7	—	84.7
Other income, net	(0.5)	0.1	(0.6)	(0.4)	(2.4)	2.0
Project Adjusted EBITDA	$ 51.3	$ 56.0	$ (4.7)	$ 159.9	$ 158.5	$ 1.4
Project Adjusted EBITDA by segment(1)						
East U.S.	19.4	27.4	(8.0)	70.5	81.0	(10.5)
West U.S.	21.3	21.4	(0.1)	43.4	37.1	6.3
Canada	10.7	7.6	3.1	46.2	43.0	3.2
Un-Allocated Corporate	(0.1)	(0.4)	0.3	(0.2)	(2.6)	2.4
Total	51.3	56.0	(4.7)	159.9	158.5	1.4

(1) Excludes the Wind Projects, which were designated a component of discontinued operations for the three and nine months ended September 30, 2015. The Wind Projects were sold in June 2015.

East U.S.

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

	Three months ended September 30, 2016	2015	% change 2016 vs. 2015
East U.S.			
Project Adjusted EBITDA	$ 19.4	$ 27.4	(29) %

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Project Adjusted EBITDA for the three months ended September 30, 2016 decreased $8.0 million from the comparable 2015 period primarily due to decreased Project Adjusted EBITDA of:

- $8.5 million at Morris due to $7.1 million of increased maintenance expense and $1.5 million lower revenue resulting from the overhaul of two gas turbines and one steam turbine in August 2016;

- $2.1 million at Curtis Palmer primarily due to lower water flows than the comparable 2015 period;

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

- $1.2 million at Orlando due to increased revenue from higher generation and lower fuel expense from lower natural gas prices.

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	Nine months ended September 30,		
	2016	2015	% change 2016 vs. 2015
East U.S.			
Project Adjusted EBITDA	$ 70.5	$ 81.0	(13) %

Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Project Adjusted EBITDA for the nine months ended September 30, 2016 decreased $10.5 million from the comparable 2015 period primarily due to decreased Project Adjusted EBITDA of:

- $9.4 million at Morris due to $8.1 million of increased maintenance expense resulting from the overhaul of two gas turbines and one steam turbine in August 2016; and
- $1.2 million at Kenilworth due to lower steam sales as a result of lower demand and higher gas turbine maintenance than the comparable 2015 period.

West U.S.

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

	Three months ended September 30,		
	2016	2015	% change 2016 vs 2015
West U.S.			
Project Adjusted EBITDA	$ 21.3	$ 21.4	(0.5) %

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Project Adjusted EBITDA for the three months ended September 30, 2016 did not change materially from the comparable 2015 period.

	Nine months ended September 30,		
	2016	2015	% change 2016 vs 2015
West U.S.			
Project Adjusted EBITDA	$ 43.4	$ 37.1	17 %

Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Project Adjusted EBITDA for the nine months ended September 30, 2016 increased $6.3 million from the comparable 2015 period primarily due to increased Project Adjusted EBITDA of:

- $7.5 million at Manchief primarily due to $8.2 million of decreased maintenance expense resulting from a scheduled maintenance overhaul in the comparable 2015 period. This was partially offset by $0.7 million of decreased revenue from lower dispatch.

This increase was partially offset by a decrease in Project Adjusted EBITDA of:

- $0.6 million at Naval Station due to a hot gas path maintenance outage.

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Canada

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

	Three months ended September 30,		
	2016	2015	% change 2016 vs. 2015
Canada			
Project Adjusted EBITDA	$ 10.7	$ 7.6	41 %

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Project Adjusted EBITDA for the three months ended September 30, 2016 increased $3.1 million from the comparable 2015 period primarily due to increases in Project Adjusted EBITDA of:

- $1.4 million at Mamquam due to higher water flows than the comparable 2015 period and a maintenance outage in the comparable 2015 period; and

- $1.4 million at Kapuskasing due to decreased maintenance expense from a turbine repair performed in the comparable 2015 period.

	Nine months ended September 30,		
	2016	2015	% change 2016 vs. 2015
Canada			
Project Adjusted EBITDA	$ 46.2	$ 43.0	7 %

Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Project Adjusted EBITDA for the nine months ended September 30, 2016 increased $3.2 million from the comparable 2015 period primarily due to an increase in Project Adjusted EBITDA of:

· $4.5 million at Mamquam due to higher water flow than the comparable 2015 period.

This increase was partially offset by decreases in Project Adjusted EBITDA of:

· $0.8 million at Calstock due to lower revenue from the expiration of a rate adder.

Un allocated Corporate

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

	Three months ended September 30,		
	2016	2015	% change 2016 vs. 2015
Un-allocated Corporate Project Adjusted EBITDA	$ (0.1)	$ (0.4)	(75) %

Three months ended September 30, 2016 compared with three months ended September 30, 2015

Project Adjusted EBITDA for the three months ended September 30, 2016 did not change materially from the comparable 2015 period.

	Nine months ended September 30,		
	2016	2015	% change 2016 vs. 2015
Un-allocated Corporate Project Adjusted EBITDA	$ (0.2)	$ (2.6)	(92) %

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Nine months ended September 30, 2016 compared with nine months ended September 30, 2015

Project Adjusted EBITDA for the nine months ended September 30, 2016 increased $2.4 million from the comparable 2015 period primarily due to an increase in Project Adjusted EBITDA of:

- $0.9 million of lower compensation expense from headcount reductions and $1.0 million in decreased development and administrative costs.

Project Adjusted EBITDA excludes the Wind Projects, which are designated as discontinued operations for the three and nine months ended September 30, 2015. Project Adjusted EBITDA for the Wind Projects was $28.3 million for the nine months ended September 30, 2015.

Liquidity and Capital Resources

	September 30, 2016	December 31, 2015
Cash and cash equivalents	$ 93.8	$ 72.4
Restricted cash	12.6	15.2
Total	106.4	87.6
Revolving credit facility availability	111.3	106.0
Total liquidity	$ 217.7	$ 193.6

Overview

Our primary source of liquidity is 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 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 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, 2015.

We expect to reinvest approximately $55.0 million in our portfolio in the form of project capital expenditures and maintenance expenses in 2016, of which $43.4 million has been incurred through September 30, 2016. 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, 2015. We do not expect any other material or unusual requirements for cash outflows for 2016 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:

	Nine months ended September 30,		
	2016	2015	Change
Net cash provided by operating activities	$ 91.9	$ 67.7	$ 24.2
Net cash provided by investing activities	0.8	323.6	(322.8)
Net cash provided by (used) in financing activities	(71.3)	(424.8)	353.5

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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 nine months ended September 30, 2016, the net increase in cash flows from operating activities of $24.2 million was primarily the result of the following:

· Decrease in interest payments – We made $32.3 million in lower interest payments than the comparable 2015 period primarily due to the redemption of the 9.0% High Yield Notes in July 2015 and the repurchase and cancellation of, in full, our Series A and B and, in part, our Series C convertible debentures during 2016.

This increase was partially offset by a decrease in net cash provided by operating activities primarily resulting from the following:

· Sale of Wind Projects – in the first nine months of 2015, the Wind Projects, which were sold in June 2015, provided $21.9 million of operating cash flows.

Investing Activities

For the nine months ended September 30, 2016, the net decrease in cash flows from investing activities of $322.8 million was primarily the result of the following:

· Sale of Wind Projects – we received $326.3 million of net proceeds from the sale of Wind Projects and the Frontier solar development project in the second quarter of 2015.

This decrease was partially offset by an increase in net cash provided by investing activities primarily the result of the following:

- Reimbursement of construction cost – we received a reimbursement of $4.7 million for the construction project at Morris.

Financing Activities

For the nine months ended September 30, 2016, the net increase in cash flows used in financing activities of $353.5 million was primarily the result of the following:

- The New Credit Facilities – we received $679.0 million of net proceeds from issuance of the New Credit Facilities; and

- Dividend payments– we paid $12.3 million of dividends on our common shares and to non-controlling interests in 2015 as compared to zero dividend payments made in 2016.

This increase was partially offset by decreases in net cash used by financing activities primarily as a result of the following:

- Corporate and project-level debt – we redeemed the Senior Secured Credit Facilities in full for $447.9 million in the second quarter of 2016 as compared to the $319.9 million paid to redeem our 9.0% Notes in 2015, and we made $9.0 million of higher principal payments on our corporate and project-level debt than the comparative 2015 period;

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- Convertible debenture repayments – we redeemed and cancelled Series A and B convertible debentures in full and the Series C convertible debentures, in part, with payments totaling $187.4 million;

- Deferred financing costs – we paid $16.2 million in deferred financing costs related to the New Credit Facilities; and

- Common share repurchases – we purchased and cancelled 5.7 million common shares at a cost of $13.9 million primarily with a portion of the proceeds from the New Credit Facilities.

Corporate Debt

The following table summarizes the maturities of our corporate debt at September 30, 2016:

	Maturity Date	Interest Rates		Remaining Principal Repayments	2016	2017	2018	2019	2020	Thereafter
Senior Secured Term Loan Facility(1)	April 2023	6.00 %	- 6.20 %	$ 654.9	$ 15.0	$ 100.0	$ 90.0	$ 65.0	$ 105.0	$ 279.9
Atlantic Power Income LP Note	June 2036	5.95 %		160.1	—	—	—	—	—	160.1
Convertible Debenture(2)	June 2019	5.75 %		42.6	—	—	—	42.6	—	—
Convertible Debenture	December 2019	6.00 %		61.7	—	—	—	61.7	—	—
Total Corporate Debt				$ 919.3	$ 15.0	$ 100.0	$ 90.0	$ 169.3	$ 105.0	$ 440.0

(1) The New Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of 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 New Credit Facilities and the MTNs, letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., 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 New Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP

Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited from paying dividends to its shareholders.

(2) In July 2016, we purchased and cancelled $62.7 million principal amount of the outstanding convertible debentures maturing June 30, 2019 under a substantial issuer bid.

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 September 30, 2016. 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 November 4, 2016, 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.

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The range of interest rates presented represents the rates in effect at September 30, 2016. 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	2016	2017	2018	2019	2020	Therea
onsolidated ojects:									
psilon ower rtners	January 2019	3.40 %	$ 15.0	$ 1.5	$ 6.3	$ 6.5	$ 0.7	$ —	$ —
edmont	August 2018	8.47 %	57.5	0.8	2.5	54.2	—	—	—
adillac	August 2025	6.19 %	27.7	0.6	3.0	3.0	3.1	3.1	14.9
otal onsolidated ojects			100.2	2.9	11.8	63.7	3.8	3.1	14.9
quity ethod ojects:									
hambers(1)	December 2019 and 2023	4.50 % - 5.00 %	42.9		—	—	5.2	7.8	29.9
otal Equity ethod ojects			42.9	—	—	—	5.2	7.8	29.9
otal oject-Level ebt			$ 143.1	$ 2.9	$ 11.8	$ 63.7	$ 9.0	$ 10.9	$ 44.8

(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, New Term Loan facility, MTNs and other corporate and project-level debt, funding the repurchase of shares of our common stock, our convertible debentures, our preferred shares (to the extent we choose to pursue any such repurchases), collateral and investment in our projects through capital expenditures, including major maintenance and business development costs and dividend payments to preferred shareholders of a subsidiary company. We may fund future acquisitions with a combination 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, although we can provide no assurances regarding the availability of public or private financing on acceptable terms or at all.

Capital and Maintenance Expenditures

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

We expect to reinvest approximately $8.2 million in 2016 (of which $6.5 million was reinvested in the nine months ended September 30, 2016) in our portfolio in the form of project capital expenditures and incur $46.8 million of maintenance expenses (of which $36.8 million was incurred in the nine months ended September 30, 2016). 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, 2015. We do not expect any other material or unusual requirements for cash outflows for 2016 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 2016 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

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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 September 30, 2016, 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, 2015.

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 Rules 13a 15(e) and 15d 15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were not effective as of September 30, 2016 as a result of the material weakness that exists in our internal control over financial reporting as previously described in our Annual Report on Form 10-K for the year ended December 31, 2015.

Previously Identified Material Weakness

As of December 31, 2015, Management concluded that our internal control over financial reporting was not effective due to the material weakness identified. Management concluded that the long-lived asset and goodwill impairment tests were not designed effectively to ensure the proper application of U.S. GAAP over (i) the determination of the carrying value of our asset groups and reporting units used in the accounting for long-lived asset recoverability and goodwill impairment test, and (ii) the determination of the long-lived asset and goodwill impairment charges. Specifically, with respect to (i) and (ii), we did not design and maintain effective controls related to determining the carrying value of the asset groups for the purpose of performing the long-lived asset impairment testing as we did not appropriately include the carrying value of goodwill in certain long-lived asset groups in which the asset group is at the same level as the reporting unit. This resulted in an initial conclusion that no long-lived asset impairment should be recorded and also impacted the carrying value of our reporting units for step 1 and step 2 of our goodwill impairment tests. These control deficiencies resulted in misstatements related to goodwill, property, plant and equipment, deferred income taxes and impairment, within the preliminary consolidated financial statements that were corrected prior to the issuance of the Company’s consolidated financial statements as of and for the fiscal year ended December 31, 2015.

A material weakness is defined as a deficiency, or combination of deficiencies in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of the Company’s annual or interim financial statements will not be prevented or detected in a timely manner.

Management’s Remediation Plan

Management is actively engaged in the implementation of remediation efforts to address the material weakness identified above. Management has taken and will continue to take the following actions to address the material weakness:

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Re-designing its controls, including the implementation of new controls, relating to the long-lived asset and goodwill impairment analysis, including: (i) enhancing the design and documentation of management review controls in order to enhance the precision at which management review controls operate, (ii) improving the documentation of internal control procedures, and (iii) enhancing internal controls over the evaluation of the components of carrying value and comparison to the requirements of generally accepted accounting principles.

We have implemented some of these re-designed controls and will continue to refine and assess the operating effectiveness of these controls through year end. We expect to have the material weakness remediated as of December 31, 2016.

Changes in Internal Control over Financial Reporting

Other than the changes described in Management's Remediation Plan above, there has been no change in our internal control over financial reporting during the three and nine months ended September 30, 2016 that has materially affected, or is 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, 2015 (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, 2015 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 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

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

Share Repurchase Program

On December 22, 2015, our Board of Directors approved a normal course issuer bid ("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 permits the Company to repurchase shares through open market repurchases. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions and other factors. The NCIB will expire on December 28, 2016 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIB. Under the NCIB, we may purchase up to a total of 12,139,215 common shares (Cdn$28.0 million based on the Cdn$2.31 closing share price of our common shares on the TSX on December 31, 2015) and are limited to daily purchases of 22,600 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIB will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIB may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of 1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. From inception of the NCIB through November 4, 2016, we have repurchased and cancelled 7,072,832 common shares.

Repurchase Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares as Part of a Publicly Announced Purchase Plan	Dollar Value of Maximum Number of Shares to be Purchased Under the Plan
7/1/16 - 7/31/2016	174,248	Cdn$ 3.18	174,248	Cdn$ 22,961,139
8/1/2016 - 8/31/2016	2,248,654	Cdn$ 3.26	2,248,654	Cdn$ 17,766,748
9/1/2016 - 9/30/2016	1,230,754	Cdn$ 3.33	1,230,754	Cdn$ 14,923,706
Total	3,653,656		3,653,656	

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
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: November 7, 2016	Atlantic Power Corporation
	By: /s/ Terrence Ronan
	Name: Terrence Ronan
	Title: Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)