

## 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.

### *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.

## 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	Customer Credit Rating (S&P)
<b>East U.S. Segment</b>								
Orlando <sup>(1)</sup>	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December, 2023	A-
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	December, 2032	A-
Morris	Illinois	Natural Gas	177	100.00 %	120	Merchant	N/A	NR
					57	Equistar Chemicals, LP <sup>(2)</sup>	December, 2034	BBB+
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	December, 2028	BBB+
Chambers <sup>(1)</sup>	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric <sup>(3)</sup>	March, 2024	BBB+
					16	Chemours Co.	March, 2024	BB-
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September, 2018	AA
Curtis Palmer <sup>(4)</sup>	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December, 2027	A-
Selkirk <sup>(1)</sup>	New York	Natural Gas	345	17.70 %	61	Merchant	N/A	NR
<b>West U.S. Segment</b>								
Naval Station	California	Natural Gas	47	100.00 %	47	San Diego Gas & Electric <sup>(5)</sup>	December, 2019	A
Naval Training Center	California	Natural Gas	25	100.00 %	25	San Diego Gas & Electric <sup>(5)</sup>	December, 2019	A
North Island	California	Natural Gas	40	100.00 %	40	San Diego Gas & Electric <sup>(5)</sup>	December, 2019	A
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	May, 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April, 2022	A-
Frederickson <sup>(1)</sup>	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August, 2022	AA-
					45	Grays Harbor PUD	August, 2022	A+
					30	Franklin, Co. PUD	August, 2022	A+
Koma Kulshan <sup>(1)</sup>	Washington	Hydro	13	49.80 %	6	Puget Sound Energy	December, 2037	BBB
<b>Canada Segment</b>								
Mamquam	British Columbia	Hydro	50	100.00 %	50	British Columbia Hydro and Power Authority	September, 2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	British Columbia Hydro and Power Authority	August, 2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00 %	66	British Columbia Hydro and Power Authority	March, 2018	AAA
Calstock	Ontario	Biomass	35	100.00 %	35	Independent Electricity System Operator	June, 2020	AA
Kapuskasing	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December, 2017	AA
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December, 2022	AA
North Bay	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December, 2017	AA
Tunis <sup>(6)</sup>	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	NA	AA

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

- (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		Nine months ended	
	September 30,		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 <sup>(1)</sup>	\$ 51.3	\$ 56.0	\$ 159.9	\$ 158.5

<sup>(1)</sup> 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

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.

*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
<b>Project revenue:</b>				
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)%
	<u>101.2</u>	<u>107.5</u>	<u>(6.3)</u>	<u>(5.9)%</u>
<b>Project expenses:</b>				
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)%
	<u>90.3</u>	<u>93.7</u>	<u>(3.4)</u>	<u>(3.6)%</u>
<b>Project other income (expense):</b>				
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 %
	<u>(68.0)</u>	<u>10.4</u>	<u>(78.4)</u>	<u>(753.8)%</u>
Project (loss) income	(57.1)	24.2	(81.3)	(336.0)%
<b>Administrative and other expenses (income):</b>				
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)%
	<u>20.6</u>	<u>26.2</u>	<u>(5.6)</u>	<u>(21.4)%</u>
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	<u>\$ (82.4)</u>	<u>\$ (6.0)</u>	<u>\$ (76.4)</u>	<u>NM</u>

	Three months ended September 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
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
	<u>31.3</u>	<u>34.1</u>	<u>35.6</u>	<u>0.2</u>	<u>101.2</u>
<b>Project expenses:</b>					
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
	<u>32.3</u>	<u>23.3</u>	<u>34.3</u>	<u>0.4</u>	<u>90.3</u>
<b>Project other income (expense):</b>					
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
	<u>(7.6)</u>	<u>0.6</u>	<u>(63.7)</u>	<u>2.7</u>	<u>(68.0)</u>
<b>Project (loss) income</b>	<u>\$ (8.6)</u>	<u>\$ 11.4</u>	<u>\$ (62.4)</u>	<u>\$ 2.5</u>	<u>\$ (57.1)</u>

	Three months ended September 30, 2015				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total <sup>(1)</sup>
<b>Project revenue:</b>					
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
	<u>38.4</u>	<u>34.6</u>	<u>34.3</u>	<u>0.2</u>	<u>107.5</u>
<b>Project expenses:</b>					
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
	<u>30.3</u>	<u>23.8</u>	<u>38.5</u>	<u>1.1</u>	<u>93.7</u>
<b>Project other income (expense):</b>					
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	—	—	—	—	—
	<u>4.3</u>	<u>0.7</u>	<u>6.1</u>	<u>(0.7)</u>	<u>10.4</u>
<b>Project income (loss)</b>	<u>\$ 12.4</u>	<u>\$ 11.5</u>	<u>\$ 1.9</u>	<u>\$ (1.6)</u>	<u>\$ 24.2</u>

<sup>(1)</sup> 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

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.

### *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.

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

The following table provides our consolidated results of operations:

	<u>Nine months ended September 30,</u>			
	<u>2016</u>	<u>2015</u>	<u>\$ change</u>	<u>% change</u>
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)%
	<u>305.8</u>	<u>321.8</u>	<u>(16.0)</u>	<u>(5.0)%</u>
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)%
	<u>265.8</u>	<u>291.8</u>	<u>(26.0)</u>	<u>(8.9)%</u>
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)%
	<u>(43.3)</u>	<u>33.0</u>	<u>(76.3)</u>	<u>(231.2)%</u>
Project (loss) income	<u>(3.3)</u>	<u>63.0</u>	<u>(66.3)</u>	<u>(105.2)%</u>
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 %
	<u>120.7</u>	<u>62.1</u>	<u>58.6</u>	<u>94.4 %</u>
(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	<u>\$ (116.2)</u>	<u>\$ 26.1</u>	<u>\$ (142.3)</u>	<u>NM</u>

	Nine months ended September 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
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
	<u>104.3</u>	<u>78.7</u>	<u>122.0</u>	<u>0.8</u>	<u>305.8</u>
<b>Project expenses:</b>					
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
	<u>94.1</u>	<u>66.8</u>	<u>103.4</u>	<u>1.5</u>	<u>265.8</u>
<b>Project other income (expense):</b>					
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
	<u>6.7</u>	<u>1.9</u>	<u>(51.7)</u>	<u>(0.2)</u>	<u>(43.3)</u>
<b>Project income (loss)</b>	<u>\$ 16.9</u>	<u>\$ 13.8</u>	<u>\$ (33.1)</u>	<u>\$ (0.9)</u>	<u>\$ (3.3)</u>

	Nine months ended September 30, 2015				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total <sup>(1)</sup>
<b>Project revenue:</b>					
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
	<u>114.8</u>	<u>83.8</u>	<u>122.7</u>	<u>0.5</u>	<u>321.8</u>
<b>Project expenses:</b>					
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
	<u>93.2</u>	<u>78.3</u>	<u>116.2</u>	<u>4.1</u>	<u>291.8</u>
<b>Project other income (expense):</b>					
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
	<u>18.4</u>	<u>1.8</u>	<u>11.4</u>	<u>1.4</u>	<u>33.0</u>
<b>Project income (loss)</b>	<u>\$ 40.0</u>	<u>\$ 7.3</u>	<u>\$ 17.9</u>	<u>\$ (2.2)</u>	<u>\$ 63.0</u>

<sup>(1)</sup> 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

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.

### *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.

## 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.

(in thousands of Net MWh)	Generation <sup>(1)</sup>		
	Three months ended	September 30,	% change
Segment	2016	2015	2016 vs. 2015
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)%

<sup>(1)</sup> 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.

(in thousands of Net MWh)	Generation <sup>(1)</sup>		
	Nine months ended	September 30,	% change
Segment	2016	2015	2016 vs. 2015
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)%

<sup>(1)</sup> 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.

*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.

Segment	Availability <sup>(1)</sup>		
	Three months ended		
	September 30,		
	2016	2015	% change 2016 vs. 2015
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)%

<sup>(1)</sup> 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.

Segment	Availability <sup>(1)</sup>		
	Nine months ended		
	September 30,		
	2016	2015	% change 2016 vs. 2015
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)%

<sup>(1)</sup> 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.

## Project Adjusted EBITDA

	Three months ended September 30,		\$ change 2016 vs 2015	Nine months ended September 30,		\$ change 2016 vs 2015
	2016	2015		2016	2015	
<b>Net (loss) income</b>	\$ (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)
<b>Project (loss) income</b>	\$ (57.1)	\$ 24.2	\$ (81.3)	\$ (3.3)	\$ 63.0	\$ (66.3)
<b>Reconciliation to Project Adjusted EBITDA</b>						
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
<b>Project Adjusted EBITDA</b>	\$ 51.3	\$ 56.0	\$ (4.7)	\$ 159.9	\$ 158.5	\$ 1.4
<b>Project Adjusted EBITDA by segment<sup>(1)</sup></b>						
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
<b>Total</b>	51.3	56.0	(4.7)	159.9	158.5	1.4

<sup>(1)</sup> 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:

East U.S.	Three months ended September 30,		% change 2016 vs. 2015
	2016	2015	
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.

	<u>Nine months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs. 2015</u>
<b>East U.S.</b>			
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:

	<u>Three months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs 2015</u>
<b>West U.S.</b>			
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.

	<u>Nine months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs 2015</u>
<b>West U.S.</b>			
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.

## Canada

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

	<u>Three months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs. 2015</u>
<b>Canada</b>			
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.

	<u>Nine months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs. 2015</u>
<b>Canada</b>			
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:

	<u>Three months ended September 30,</u>		
	<u>2016</u>	<u>2015</u>	<u>% change 2016 vs. 2015</u>
<b>Un-allocated Corporate</b>			
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.

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

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	<u>\$ 217.7</u>	<u>\$ 193.6</u>

### 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

### ***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;

- *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 <sup>(1)</sup>	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 <sup>(2)</sup>	June 2019	5.75%	42.6	—	—	—	42.6	—	—
Convertible Debenture	December 2019	6.00%	61.7	—	—	—	61.7	—	—
<b>Total Corporate Debt</b>			<b>\$ 919.3</b>	<b>\$ 15.0</b>	<b>\$ 100.0</b>	<b>\$ 90.0</b>	<b>\$ 169.3</b>	<b>\$ 105.0</b>	<b>\$ 440.0</b>

<sup>(1)</sup> 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.

<sup>(2)</sup> 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*.

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.

	<u>Maturity Date</u>	<u>Range of Interest Rates</u>	<u>Total Remaining Principal Repayments</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>Thereafter</u>
<b>Consolidated Projects:</b>									
Epsilon Power Partners	January 2019	3.40 %	\$ 15.0	\$ 1.5	\$ 6.3	\$ 6.5	\$ 0.7	\$ —	\$ —
Piedmont	August 2018	8.47 %	57.5	0.8	2.5	54.2	—	—	—
Cadillac	August 2025	6.19 %	27.7	0.6	3.0	3.0	3.1	3.1	14.9
Total Consolidated Projects			100.2	2.9	11.8	63.7	3.8	3.1	14.9
<b>Equity Method Projects:</b>									
Chambers <sup>(1)</sup>	December 2019 and 2023	4.50 % - 5.00%	42.9	—	—	—	5.2	7.8	29.9
Total Equity Method Projects			42.9	—	—	—	5.2	7.8	29.9
<b>Total Project-Level Debt</b>			<b>\$ 143.1</b>	<b>\$ 2.9</b>	<b>\$ 11.8</b>	<b>\$ 63.7</b>	<b>\$ 9.0</b>	<b>\$ 10.9</b>	<b>\$ 44.8</b>

<sup>(1)</sup> 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.

## 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: