HILLENBRAND INDUSTRIES INC
Form 4
January 04, 2005

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL
OMB Number: 3235-0287
Expires: January 31, 2005
Estimated average burden hours per response... 0.5

(Print or Type Responses)

1. Name and Address of Reporting Person *
HILLENBRAND W AUGUST

(Last) (First) (Middle)

700 STATE ROUTE 46E

(Street)

BATESVILLE, IN 47006

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
HILLENBRAND INDUSTRIES INC [HB]

3. Date of Earliest Transaction (Month/Day/Year)
12/31/2004

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Common Stock	01/04/2005		J (5)		0 (5)	D	$ 0 (5)	302,575	I	By Limited Partnership (5) (6)
Common Stock								272,443	I	By GRATs
Common Stock								110,851	I	By Spouse's GRAT (7)
Common Stock								154,584	I	By Spouse as Co-Trustee (7)
Common Stock								442,000	I	Co-Trustee

Common Stock								37,407	I	By Trusts for Grandchildren
Common Stock								49,304	I	By Family LLC
Common Stock								1,532,910	I	By Trusts
Common Stock	01/03/2005		A		732	A	$ 55.54	241,455	D	
Common Stock	01/03/2005		F		218	D	$ 55.54	241,237	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Am Underlying Secu (Instr. 3 and 4)	
								Date Exercisable	Expiration Date	Title	A or N of Sh
				Code	V	(A)	(D)				
Phantom Stock Units (Long Term Performance Shares)	$ 0 (1)	12/31/2004		A (2)		852		02/08/2005 (3)	02/08/2005 (3)	Common Stock	
Phantom Stock Units (Restricted)	$ 0 (1)	12/31/2004		A (2)		7		(8)	(8)	Common Stock	
Restricted Stock Units (i.e. Deferred Stock Award) 2/13/04	$ 0 (1)	12/31/2004		A (2)		7		02/14/2005 (4)	(4)	Common Stock	

Phantom Stock Units (Restricted)	$ 0 (1)	01/03/2005	A	732	(8)	(8)	Common Stock

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
HILLENBRAND W AUGUST 700 STATE ROUTE 46E BATESVILLE, IN 47006	X			

Signatures

W August Hillenbrand	01/04/2005
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Conversion or Exercise Price of Derivative Security is 1-for-1.

(2) Phantom stock units are entitled to dividend equivalent rights, which accrue on dividend record dates.

(3) All of these stock units will be converted into shares of common stock on 2/8/05.

(4) These stock units shall vest on the later of the date indicated, or the six-month anniversary of the date that the Director ceases to be a member of the Board of Directors of the Corporation.

(5) The Reporting Person transferred a portion of the limited partner interests in this limited partnership to his five adult children in exchange for cash and promissory notes.

(6) The Reporting Person is only a limited partner and he disclaims beneficial ownership of the securities held by the limited partnership except to the extent of this pecuniary interest.

(7) Reporting person disclaims beneficial ownership of these securities.

(8) A portion of these stock units will automatically be converted into shares of common stock on 1/3/2005 and the remainder will be converted on 1/2/06.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
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$

51.3

$

94.1

$

0.5

$

222.4

Segment assets

688.5

299.3

281.9

104.4

1,374.1

Project Adjusted EBITDA

$

56.2

$

19.8

$

72.8

$

0.5

$

149.3

Change in fair value of derivative instruments

1.3

—

4.1

(1.6)

3.8

Depreciation and amortization

22.7

19.8

26.4

0.4

69.3

Interest, net

5.3

—

—

—

5.3

Impairment

57.7

—

—

Explanation of Responses:

—

57.7

Project (loss) income

(30.8)

—

42.3

1.7

13.2

Administration

—

—

—

12.1

12.1

Interest expense, net

—

—

—

35.7

35.7

Foreign exchange loss

—

—

—

8.3

8.3

(Loss) income from continuing operations before income taxes

(30.8)

—

42.3

(54.4)

(42.9)

Income tax benefit

—

—

—

(22.6)

(22.6)

Net (loss) income from continuing operations

$

(30.8)

$

—

$

42.3

$

(31.8)

$

(20.3)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

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

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

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

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

12. Guarantees and Contingencies

Guarantees

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

Contingencies

Ontario Electricity Financial Corporation ("OEFC") Settlement

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

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

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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of June 30, 2017.

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FORWARD LOOKING INFORMATION

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

- our ability to generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities;
- the outcome or impact of our business strategy to increase our intrinsic value on a per-share basis through disciplined management of our balance sheet and cost structure and investment of our discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities;
- our ability to renew or enter into new PPAs on favorable terms or at all after the expiration of our current agreements;
- our ability to meet the financial covenants under our senior secured term loans and other indebtedness;
- expectations regarding maintenance and capital expenditures; and
- the impact of legislative, regulatory, competitive and technological changes.

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

Forward looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under “Item 1A. Risk Factors” in our Annual Report on Form 10 K for the year ended December 31, 2016 and in this Quarterly

Report on Form 10 Q. To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2016 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updates to our business strategy, such risk factors should be read in light of such information. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

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

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

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

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· our indebtedness and financing arrangements and the terms, covenants and restrictions included in our senior secured term loans;

· exchange rate fluctuations;

· the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;

· unstable capital and credit markets;

· the dependence of our projects on their electricity and thermal energy customers;

· exposure of certain of our projects to fluctuations in the price of electricity or natural gas;

· the dependence of our projects on third party suppliers;

· projects not operating according to plan;

· the effects of weather, which affects demand for electricity and fuel as well as operating conditions;

· U.S., Canadian and/or global economic conditions and uncertainty;

· risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;

· the adequacy of our insurance coverage;

· the impact of significant energy, environmental and other regulations on our projects;

· the impact of impairment of goodwill or long lived assets;

· increased competition, including for acquisitions;

· our limited control over the operation of certain minority owned projects;

· transfer restrictions on our equity interests in certain projects;

· risks inherent in the use of derivative instruments;

· labor disruptions;

· the impact of hostile cyber intrusions;

· the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and

· our ability to retain, motivate and recruit executives and other key employees.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward looking information include third party projections of regional fuel and electric capacity and energy prices that are based on assumptions about future economic conditions and courses of action. Although the forward looking statements contained in this Quarterly Report on Form 10 Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward looking statements, and the differences may be material. Certain statements included in this Quarterly Report on Form 10 Q may be considered “financial outlook” for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10 Q. These forward looking statements are made as of the date of

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this Quarterly Report on Form 10 Q and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

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

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

OVERVIEW

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

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). Our PPAs have expiration dates ranging from December 31, 2017 to December 31, 2037. Nine of our projects, representing 25% of our net MW and 30% of our 2016 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Kapuskasing (2017), North Bay (2017), Williams Lake (2018), Kenilworth (2018), Naval Station (2019), Naval Training Center (2019), North Island (2019), Calstock (2020) and Oxnard (2020). There are no PPA expirations in 2021. When a PPA expires, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. Our MW-weighted average remaining PPA life is approximately 7 years. We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

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

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

RECENT DEVELOPMENTS

San Diego Contracts

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

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

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

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

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

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

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

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

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

Impairment of Equity Method Investments

Selkirk

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

Chambers

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. Chambers operates under a PPA that expires in March 2024. During the second quarter of 2017, we performed an analysis of the post-PPA value of Chambers operating as a merchant facility. While declining power prices have been observed over the past several years, we identified a significant decrease in the long-term outlook for power prices in the region where Chambers operates in our most recent long-term forecast. These forward prices obtained from a third party, including the price of gas and coal, had a significant negative impact on the estimated discounted cash flows of Chambers. The estimated post-PPA value is a significant component of the project's overall value when compared to its carrying value of $124 million.

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

OEFC Settlement

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

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

Senior secured term loan facility repricing

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

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OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of August 1, 2017, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. Our customers are generally large utilities and other parties with investment grade credit ratings, as measured by Standard & Poor's ("S&P"). For customers rated by Moody's, we substitute the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment grade have weaker capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	C C R (S
East U.S. Segment								
Orlando(1)	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December, 2023	
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September, 2032	
Morris	Illinois	Natural Gas	177	100.00 %	120	Merchant	N/A	
					57	Equistar Chemicals, LP(2)	December, 2034	
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June, 2028	
Chambers(1)	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric(3)	March, 2024	
					16	Chemours Co.	March, 2024	
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September, 2018	
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December, 2027 (4)	
Selkirk(1)	New York	Natural Gas	345	17.70 %	61	Merchant	N/A	
West U.S. Segment								
Naval Station	California		47	100.00 %	47			

		Natural Gas				San Diego Gas & Electric	November, 2019 (5)
Naval Training Center	California	Natural Gas	25	100.00 %	25	San Diego Gas & Electric	November, 2019 (5)
North Island	California	Natural Gas	40	100.00 %	40	San Diego Gas & Electric	November, 2019 (5)
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	April, 2020
Manchief	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April, 2022 (6)
Frederickson(1)	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August, 2022
					45	Grays Harbor PUD	August, 2022
					30	Franklin, Co. PUD	August, 2022
Koma Kulshan(1)	Washington	Hydro	13	49.80 %	6	Puget Sound Energy	March, 2037
Canada Segment							
Mamquam	British Columbia	Hydro	50	100.00 %	50	British Columbia Hydro and Power Authority	September, 2027
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	British Columbia Hydro and Power Authority	August, 2022
Williams Lake	British Columbia	Biomass	66	100.00 %	66	British Columbia Hydro and Power Authority	March, 2018
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June, 2020
Kapuskasing	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 (7)
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2022 (8)
North Bay	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 (7)
Tunis	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	(9)

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

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Explanation of Responses:

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

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

(4) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through June 30, 2017, the facility has generated 7,173 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

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

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

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

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

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

Consolidated Overview and Results of Operations

Performance highlights

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

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

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

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

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

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

These increases in project revenue were partially offset by:

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

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

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

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

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

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

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

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

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

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

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

These increases in project revenue were partially offset by:

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

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

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

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

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

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

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

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

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

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

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

The following table provides our consolidated results of operations:

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

The following tables provide our project income by segment:

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

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

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

East U.S.

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

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

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

These decreases were partially offset by:

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

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

West U.S.

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

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

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

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

Canada

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

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

These increases were partially offset by:

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

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

Un allocated Corporate

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

Administrative and other expenses (income)

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

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the U.S. dollar equivalent of our Canadian dollar denominated obligations and the related deferred income tax expense (benefit) associated with these non cash items.

Administration

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

Interest expense, net

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

Foreign exchange loss

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

Other expense, net

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

Income tax expense

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

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

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

The following table provides our consolidated results of operations:

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

The following tables provide our project income by segment:

Explanation of Responses:

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

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

East U.S.

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

- decreased project income of $47.4 million and $11.0 million at Chambers and Selkirk, respectively, primarily due to impairments of $47.1 million and $10.6 million recorded in the six months ended June 30, 2017;

- decreased project income of $6.8 million at Orlando primarily due to a $8.5 million decrease in the change in fair value of derivatives and a maintenance outage, partially offset by lower fuel expense resulting from the settlement of favorable fuel swaps; and

- decreased project income of $3.7 million at Morris primarily due to higher fuel prices and lower energy and

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capacity revenue than in the comparable 2016 period.

These decreases were partially offset by:

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

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

West U.S.

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

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

Canada

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

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

These increases were partially offset by:

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

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

Un allocated Corporate

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

Administrative and other expenses (income)

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

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Administration

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

Interest expense, net

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

Foreign exchange loss

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

Other income, net

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

Income tax expense

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

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

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Project Operating Performance

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours (“MWh”). Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was not material for the three and six months ended June 30, 2017. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in Net Gigawatt-hours (GWh).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

- decreased availability in the Canada segment primarily due to a forced outage at Mamquam;
- decreased availability in the West U.S. segment primarily due to a planned maintenance outage at Frederickson; and
- decreased availability in the East U.S. segment primarily due to planned maintenance outages at Kenilworth and Morris.

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Supplementary Non GAAP Financial Information

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

Project Adjusted EBITDA

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

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

East U.S.

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

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

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

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

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

· $1.3 million at Piedmont primarily due to a maintenance outage that occurred in the comparable 2016 period.

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

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

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

· $6.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period;

· $1.9 million at Piedmont primarily due to a maintenance outage that occurred in the comparable 2016 period; and

· $1.7 million at Orlando primarily due to lower fuel expenses resulting from the settlement of favorable fuel swaps.

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

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

West U.S.

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

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

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

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

- $2.7 million at Frederickson primarily due to higher planned maintenance expense than the comparable 2016 period;
- $0.7 million at Naval Station primarily due to lower steam revenue than the comparable 2016 period; and

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

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

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

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

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

Canada

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

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

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

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

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

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

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

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

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

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

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

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and Kapuskasing from the comparable 2016 period.

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

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

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

Un allocated Corporate

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

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

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

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

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

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

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

Liquidity and Capital Resources

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

Overview

Our primary sources of liquidity are distributions from our projects and availability under our revolving credit facility. Our future liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from December 31, 2017 (at our North Bay and Kapuskasing projects) to December 2037. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements or we may elect to operate certain facilities in the merchant market upon expiration of their PPAs. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of

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and investment in accretive growth opportunities (both internal and external), to the extent available, repurchase of common shares and other allocation of available cash. See “Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations” in our Annual Report on Form 10 K for the year ended December 31, 2016.

We expect to reinvest approximately $46.7 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2017, of which $22.6 million has been incurred through June 30, 2017. Such investments are generally paid at the project level. See “—Capital and Major Maintenance Expenditures” in our Annual Report on Form 10 K for the year ended December 31, 2016. We do not expect any other material or unusual requirements for cash outflows for 2017 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

Consolidated Cash Flow Discussion

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

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

Operating Activities

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

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

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

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

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

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

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

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

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

Investing Activities

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

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

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

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

Financing Activities

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

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

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

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

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

Corporate Debt

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

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

(1) The senior secured term loans contain a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings Limited Partnership (“APLP Holdings”) and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the senior secured credit facilities and the Medium Term Notes, letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of senior secured term loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an

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event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited being unable to pay dividends to its shareholders. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above.

Project Level Debt

Project level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project level debt. The amounts represent our share of the non recourse project level debt balances at June 30, 2017. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. At August 1, 2017, all of our projects with the exception of Piedmont were in compliance with the covenants contained in project level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but are not callable or subject to acceleration under the terms of their debt agreements. We do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before the project's debt maturity in 2018 at the earliest. See Note 6 to the consolidated financial statements of this Quarterly Report on Form 10-Q, Long term debt—Non Recourse Debt.