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

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

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

OVERVIEW

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long‑term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of October 31, 2018, our portfolio consisted of twenty-two projects with an aggregate electric generating capacity of approximately 1,793 megawatts ("MW") on a gross ownership basis and approximately 1,447 MW on a net ownership basis. Nineteen of the projects are majority‑owned by the Company. Two of our Ontario projects were not in operation, because of contract expirations on December 31, 2017. In early February 2018, our three plants in San Diego, totaling 112 MW on a gross and net ownership basis, ceased operations . The seventeen projects in operation at October 31, 2018 have generating capacity of approximately 1,601 MW on a gross ownership basis and approximately 1,255 MW on a net ownership basis.

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 June 30, 2019 to March 31, 2037. We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

We directly operate and maintain nineteen of our power generation projects (fourteen of which are currently in operation). 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

Term Loan Repricing

On October 31, 2018, the repricing of the $470 million senior secured term loan facility became effective. As a result of the repricing, the interest rate margin on the term loan and revolver was reduced by 0.25% to LIBOR plus 2.75% with no change to the 1.00% LIBOR floor.

South Carolina Biomass Plants Acquisition

On September 20, 2018, we executed an agreement to acquire two biomass plants in South Carolina from EDF Renewables for $13.0 million. Closing of the transaction is expected to occur late in the third quarter or in the fourth quarter of 2019, subject to restructuring of the plants' ownership structure by EDF Renewables after the end of relevant tax credit recapture periods. We have paid $2.6 million of the purchase price, which will be held in escrow until the closing date. The remainder of the purchase price will be paid at closing.

Each of the plants has a capacity of 20 megawatts. All of the output of the two plants is sold to Santee Cooper, a state-owned utility, under PPAs that run to 2043. Under the terms of the PPAs, the plants receive energy payments for energy produced. The fuel cost component of the energy revenues is based on a biomass market index. There is no project-level debt at either plant.

Koma Kulshan Acquisition

On June 18, 2018, we purchased a 0.5% general partner interest in Concrete for $1.1 million from Mt. Baker Corporation with cash on-hand. Prior to the purchase, we owned a 0.5% general partner interest and a 99.0% limited partner interest in Concrete; following the purchase, we own 100% of the entity. Concrete is the owner of a 50% limited partner interest in Koma. As a result of the purchase, our ownership of Koma increased from 49.75% to 50.00%. With 50.00% percent ownership of Koma, we did not have financial control of the entity as t he two owner parties had joint control and substantive participating rights through the structure of the partnership agreement. Accordingly, since we did not obtain control of the project, we continued to account for Koma under the equity method of accounting as of June 30, 2018. The $1.1 million purchase was accounted for as an additional equity method investment in Koma.

On July 27, 2018, we acquired the remaining 50% partnership interest in Koma from Covanta Energy Americas, Inc. ("Covanta") and bought out the operation and maintenance contract held by Covanta for a total purchase price of $12.5 million, including $0.8 million of working capital. As a result of the purchase, we now own 100% of Koma and consolidated the project on the acquisition date.

The purchase was accounted for under the acquisition method of accounting, which included allocating the purchase price to both the tangible and intangible assets and liabilities of Koma. Additionally, we recognized a $6.7 million gain in the consolidated statements of operations for the three and nine months ended September 30, 2018 as a result of remeasuring our previous 50% equity interest in Koma immediately before the business combination to fair value. No goodwill was recorded as a result of the Koma acquisition. The $12.5 million total purchase price was funded with cash on-hand. We assumed operation of the project from Covanta on the acquisition date of July 27, 2018.

Share Repurchase Program

Under the NCIBs commenced on December 29, 2017, we repurchased and cancelled 475,000 of our Series 1 Preferred Shares, 5,000 of our Series 2 Preferred Shares and 164,790 of our Series 3 Preferred Shares at a total cost of $8.0 million, resulting in a $7.9 million gain recorded in net (loss) income attributable to preferred shares of a subsidiary company in the nine months ended September 30, 2018. Through September 30, 2018, we also repurchased and cancelled approximately 5.8 million common shares at a cost of $12.3 million.

OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of October 31, 2018, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. Our customers are generally large utilities and other parties with investment-grade credit ratings, as measured by Standard & Poor's ("S&P"). For customers rated by Moody's, we substitute the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment-grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment-grade have weaker capacity. Agency ratings are subject to change, and there can be no assurance that a rating agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
East U.S. Segment								
Orlando [1]	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December 2023	A–
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September 2032	A–
Morris [2]	Illinois	Natural Gas	177	100.00 %	120	Merchant	N/A	NR
					57	Equistar Chemicals, LP	December 2034	BBB+ [3]
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	BBB+
Chambers [1]	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric [4]	March 2024	BBB+
					16	Chemours Co.	March 2024	BB
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2019 [5]	AA
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 [6]	A–
West U.S. Segment								
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	April 2020 [7]	BBB+
Manchief [8]	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022	A–
Frederickson [1]	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	Washington	Hydro	13	100.00 %	13	Puget Sound Energy	March 2037	BBB
Canada Segment								
Mamquam [9]	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	June 2019	AAA
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June 2020	AA
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December 2022 [10]	AA
Tunis	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	October 2033 [11]	AA

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

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

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

(4) 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.

(5) Merck has two additional successive one-year extension options.

(6) 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, 2018, the facility has generated 7,511 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

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

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

(9) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021.

(10) In December 2017, we entered into a long-term enhanced dispatch contract with the IESO for Nipigon for the period from November 1, 2018 through December 31, 2022. As a result, the PPA terminated effective October 31, 2018. The long-term enhanced dispatch contract provides for Nipigon to receive monthly capacity-type payments based on

the original PPA, with adjustment for operational savings that will be shared with the IESO. In addition, the project will function as a market participant and earn energy revenues for those periods during which it operates.

(11) 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 contract with the IESO that commenced on October 4, 2018. The contract provides the Tunis project with a fixed monthly payment which escalates annually according to a pre-defined formula while allowing the project to earn additional energy revenues for those periods during which it operates. The contract is based on an average annual capacity of 36.5 MW.

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

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

(1) In August 2018, we terminated discussions with the Navy regarding site control for Naval Station, NTC and North Island. We are proceeding with plans to decommission all three sites in 2019, which is a requirement of our land use agreements with the Navy. Pending a determination with the Navy regarding the scope of work and receipt of bids from contractors, the final cost of the decommissioning may exceed our asset retirement obligation of $1.7 million.

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, 2018 and 2017, which are analyzed in greater detail below:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Project revenue	$ 65.4	$ 108.6	$ 211.6	$ 331.0
Project income (loss)	$ 26.2	$ (20.9)	$ 68.0	$ (7.7)
Net (loss) income attributable to Atlantic Power Corporation	$ (3.2)	$ (32.9)	$ 12.1	$ (57.5)
(Loss) income per share attributable to Atlantic Power Corporation—basic	$ (0.03)	$ (0.29)	$ 0.11	$ (0.50)
(Loss) income per share attributable to Atlantic Power Corporation—diluted	$ (0.03)	(0.29)	0.11	(0.50)
Project Adjusted EBITDA [1]	$ 45.4	$ 77.4	$ 138.5	$ 226.6

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

Project revenue decreased by $43.2 million to $65.4 million in the three months ended September 30, 2018 from $108.6 million in the three months ended September 30, 2017. The primary drivers of the decrease are as follows:

- *San Diego projects* – the Naval Station, North Island and NTC projects ceased operations in February 2018. This resulted in a $22.9 million decrease in project revenue;
- *Enhanced dispatch contracts* – the enhanced dispatch contracts with the IESO for Kapuskasing and North Bay expired in December 2017, which resulted in a $12.0 million decrease in project revenue;

- *Williams Lake* – the energy purchase agreement extension became effective in April 2018, which provides lower pass-through of costs than the previous contract. The project also had lower dispatch than the comparable 2017 period. These factors resulted in a $5.7 million decrease in project revenue; and

- *Curtis Palmer* – lower water flows resulted in a $3.5 million decrease in revenue from the comparable 2017 period.

Consolidated project income increased by $47.1 million to $26.2 million in the three months ended September 30, 2018 from a project loss of $20.9 million in the three months ended September 30, 2017. The primary drivers of the increase are as follows:

- *Impairment* – we recorded $57.3 million of long-lived asset impairments at Naval Station, NTC and North Island in the comparable 2017 period;

- *Depreciation and amortization expense* – depreciation and amortization expense decreased by $10.4 million from the comparable 2017 period primarily due to decreases of $4.6 million and $4.0 million at our Kapuskasing and North Bay projects, respectively, which were fully depreciated as of December 31, 2017, a $4.3 million decrease at our San Diego projects due to accelerated depreciation beginning in the third quarter of 2017 and a $1.7 million decrease at Williams Lake, which recorded a $29.1 million impairment in the fourth quarter of 2017. These decreases were partially offset by $4.2 million of increased amortization of the PPA intangible asset at our Nipigon project;

- *Fuel expense* – fuel expense decreased $9.5 million from the comparable 2017 period primarily due to a $9.6 million decrease at the Naval Station, North Island and NTC projects, which ceased operations in February 2018; and

- *Purchase accounting gain* – we recorded a $6.7 million gain related to the remeasurement of our previous 50% equity ownership of Koma to fair value resulting from the acquisition of the remaining 50% in July of 2018.

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

- *Project revenue* – project revenue decreased $43.2 million as discussed above.

Project revenue decreased by $119.4 million to $211.6 million in the nine months ended September 30, 2018 from $331.0 million in the nine months ended September 30, 2017. The primary drivers of the decrease are as follows:

- *San Diego projects* – the Naval Station, North Island and NTC projects ceased operations in February 2018, which resulted in a $52.6 million decrease in project revenue;

- *Enhanced dispatch contracts* – the enhanced dispatch contracts with the IESO for Kapuskasing and North Bay expired in December 2017, which resulted in a $38.2 million decrease in project revenue;

- *OEFC settlement* – we recorded $25.6 million of project revenue related to the OEFC settlement in the comparable 2017 period at our North Bay, Kapuskasing and Tunis projects and did not receive a settlement in 2018;

- *Williams Lake* – the energy purchase agreement extension became effective in April 2018, which provides lower pass-through of costs than the previous contract. These factors resulted in an $8.5 million decrease in project revenue; and

- *Curtis Palmer* – lower water flows resulted in a $6.2 million decrease in revenue from the comparable 2017 period.

These decreases were partially offset by:

- *Morris project* – there was a $5.6 million increase in revenue at our Morris project due to higher capacity prices, higher merchant dispatch and higher steam and ancillary services than the comparable 2017 period; and

- *Piedmont debt* – we recorded a $1.0 million loss from an interest rate swap and $1.7 million of interest expense related to Piedmont's project-level debt that was repaid, in full, in the fourth quarter of 2017.

Consolidated project income increased by $75.7 million to $68.0 million in the nine months ended September 30, 2018 from a project loss of $7.7 million in the nine months ended September 30, 2017. The primary drivers of the increase are as follows:

- *Impairment* – we recorded $57.3 million of impairments at our wholly-owned Naval Station, NTC and North Island projects, and $57.7 million of impairments at our Chambers and Selkirk projects, which are accounted under the equity method of accounting in the comparable 2017 period;

- *Fuel expense* – fuel expense decreased $25.2 million from the comparable 2017 period primarily due to a $24.4 million decrease at the Naval Station, North Island and NTC projects, which ceased operations in February 2018;

- *Depreciation and amortization expense* – depreciation and amortization expense decreased by $24.8 million from the comparable 2017 period primarily due to decreases of $13.5 million and $11.4 million at our Kapuskasing and North Bay projects, respectively, which were fully depreciated as of December 31, 2017 and a decrease of $8.5 million at our San Diego projects due to accelerated depreciation beginning in the third quarter of 2017. This decrease was partially offset by $13.2 million of increased amortization of the PPA intangible asset at our Nipigon project;

- *Equity in earnings from unconsolidated affiliates* – excluding the $57.7 million of impairments at our Chambers and Selkirk projects discussed above, our equity in earnings from unconsolidated affiliates increased by $12.1 million for the nine months ended September 30, 2018 primarily due to a $5.8 million increase at Frederickson from lower maintenance expense and a $4.5 million increase at Orlando from higher availability and contractual capacity prices than the comparable 2017 period;

- *Fuel swap and natural gas purchase agreements* – the change in fair value of our derivative instruments increased $9.4 million from the comparable 2017 period; and

- *Purchase accounting gain* – we recorded a $6.7 million gain related to the remeasurement of our previous 50% equity ownership of Koma to fair value. This resulted from the acquisition of the remaining 50% in July of 2018.

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

- *Project revenue* – project revenue decreased $119.4 million as discussed above.

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 54.

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.

Three months ended September 30, 2018 compared to the three months ended September 30, 2017

The following table provides our consolidated results of operations:

	Three months ended September 30,			
	2018	2017	$ change	% change
Project revenue:				
Energy sales	$ 25.0	$ 36.5	$ (11.5)	(31.5)%
Energy capacity revenue	29.5	37.9	(8.4)	(22.2)%
Other	10.9	34.2	(23.3)	(68.1)%
	65.4	108.6	(43.2)	(39.8)%
Project expenses:				
Fuel	16.7	26.2	(9.5)	(36.3)%
Operations and maintenance	18.0	19.8	(1.8)	(9.1)%
Depreciation and amortization	21.0	31.4	(10.4)	(33.1)%
	55.7	77.4	(21.7)	(28.0)%
Project other income (loss):				
Change in fair value of derivative instruments	—	(1.9)	1.9	(100.0)%
Equity in earnings of unconsolidated affiliates	10.2	9.2	1.0	NM [1]
Interest, net	(0.4)	(2.2)	1.8	(81.8)%
Impairment	—	(57.3)	57.3	(100.0)%
Other income, net	6.7	0.1	6.6	NM
	16.5	(52.1)	68.6	(131.7)%
Project income (loss)	26.2	(20.9)	47.1	NM
Administrative and other expenses:				
Administration	5.7	5.5	0.2	3.6 %
Interest expense, net	14.6	13.8	0.8	5.8 %
Foreign exchange loss	4.5	9.4	(4.9)	(52.1)%
Other expense, net	2.5	—	2.5	NM
	27.3	28.7	(1.4)	(4.9)%
Loss from operations before income taxes	(1.1)	(49.6)	48.5	(97.8)%
Income tax expense (benefit)	3.6	(15.9)	19.5	NM
Net loss	(4.7)	(33.7)	29.0	(86.1)%
Net income attributable to preferred shares of a subsidiary company	(1.5)	(0.8)	(0.7)	87.5 %
Net loss attributable to Atlantic Power Corporation	$ (3.2)	$ (32.9)	$ 29.7	(90.3)%

(1) NM is defined as “not meaningful” and includes changes greater than 200%.

	Three months ended September 30, 2018				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 16.0	$ 3.3	$ 5.7	$ —	$ 25.0
Energy capacity revenue	16.6	10.2	2.7	—	29.5
Other	3.7	0.3	6.7	0.2	10.9
	36.3	13.8	15.1	0.2	65.4
Project expenses:					
Fuel	12.2	2.1	2.4	—	16.7
Operations and maintenance	9.7	3.7	4.4	0.2	18.0
Depreciation and amortization	9.1	4.0	7.9	—	21.0
	31.0	9.8	14.7	0.2	55.7
Project other income (expense):					
Change in fair value of derivative instruments	(0.5)	—	0.8	(0.3)	—
Equity in earnings of unconsolidated affiliates	8.3	1.9	—	—	10.2
Interest expense, net	(0.4)	—	—	—	(0.4)
Other income, net	—	6.7	—	—	6.7
	7.4	8.6	0.8	(0.3)	16.5
Project income (loss)	$ 12.7	$ 12.6	$ 1.2	$ (0.3)	$ 26.2

	Three months ended September 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 20.1	$ 8.4	$ 8.0	$ —	$ 36.5
Energy capacity revenue	16.3	19.0	2.6	—	37.9
Other	3.4	7.7	22.9	0.2	34.2
	39.8	35.1	33.5	0.2	108.6
Project expenses:					
Fuel	11.6	11.4	3.2	—	26.2
Operations and maintenance	8.7	5.6	5.7	(0.2)	19.8
Depreciation and amortization	9.1	8.1	14.1	0.1	31.4
	29.4	25.1	23.0	(0.1)	77.4
Project other income (expense):					
Change in fair value of derivative instruments	(1.3)	—	(1.2)	0.6	(1.9)
Equity in earnings of unconsolidated affiliates	8.1	1.1	—	—	9.2
Interest expense, net	(2.2)	—	—	—	(2.2)
Impairment	—	(57.3)	—	—	(57.3)
Other income, net	—	—	0.1	—	0.1
	4.6	(56.2)	(1.1)	0.6	(52.1)
Project income (loss)	$ 15.0	$ (46.2)	$ 9.4	$ 0.9	$ (20.9)

East U.S.

Project income for the three months ended September 30, 2018 decreased $2.3 million from the comparable 2017 period primarily due to:

- decreased project income of $3.2 million at Curtis Palmer primarily due to lower water flows than the comparable 2017 period;
- decreased project income of $1.1 million at Cadillac primarily due to a $0.8 million decrease in revenue resulting from a maintenance outage in the three months ended September 30, 2018; and
- decreased project income of $1.0 million at Kenilworth primarily due to a $0.7 million increase in maintenance expense from a gas turbine overhaul that occurred in the three months ended September 30,

2018.

These decreases were partially offset by:

- increased project income of $2.5 million at Piedmont primarily due to $1.7 million of lower interest expense resulting from the repayment of the project-level debt, in full, in 2017.

West U.S.

Project income for the three months ended September 30, 2018 increased $58.8 million from a project loss in the comparable 2017 period primarily due to:

- increased project income of $19.7 million, $18.7 million and $11.9 million at Naval Station, North Island and NTC primarily due to $22.5 million, $13.5 million and $21.2 million long-lived asset impairments recorded for the comparable 2017 period, respectively; and

- increased project income of $6.5 million at Koma primarily due to a $6.7 million purchase accounting gain recognized from a step acquisition of the 50% remaining interest in Koma.

Canada

Project income for the three months ended September 30, 2018 decreased $8.2 million from the comparable 2017 period primarily due to:

- decreased project income of $3.2 million at Williams Lake primarily due to lower gross margin under the short-term contract extension that become effective in April 2018;

- decreased project income of $1.6 million at Nipigon primarily due to a $4.2 million increase in amortization expense from accelerated amortization of the intangible PPA asset, partially offset by a $2.1 million increase in fair value of fuel purchase agreements;

- decreased project income of $1.5 million at Kapuskasing primarily due to $6.6 million of revenue recorded related to the OEFC settlement in the comparable period in 2017 and the expiration of the enhanced dispatch contract, partially offset by a $4.7 million decrease in depreciation expense; and

- decreased project income of $1.1 million at North Bay primarily due to $5.4 million of revenue recorded related to the OEFC settlement in the comparable period in 2017 and the expiration of the enhanced dispatch contract, partially offset by a $4.0 million decrease in depreciation expense.

Un-allocated Corporate

Project income for the three months ended September 30, 2018 decreased $1.2 million from the comparable 2017 period primarily due to a $0.9 million decrease in change in fair value of interest swaps related to the senior secured credit facility.

Administrative and other expenses (income)

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

Administration

Administration expense did not change materially from the 2017 comparable period.

Interest expense, net

Interest expense did not change materially from the 2017 comparable period.

Foreign exchange loss (gain)

Foreign exchange loss decreased by $4.9 million to $4.5 million in the three months ended September 30, 2018 from a $9.4 million loss in the comparable 2017 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and convertible debentures). The Canadian dollar appreciated 1.7% against the U.S. dollar from June 30, 2018 to September 30, 2018, as compared to a 4.0% appreciation in the comparable 2017 period.

Other expense, net

Other expense increased by $2.5 million from the comparable 2017 period due to a $2.6 million decrease in the fair value of the convertible debenture conversion option.

Income tax expense

Income tax expense for the three months ended September 30, 2018 was $3.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 27%, was $0.3 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017 which have been reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, and base erosion and anti-abuse tax. Based on estimates as of the date of this filing, we will not be subject to the base erosion and anti-abuse tax. Our interest expense deduction may be limited, but will not have a material impact on cash taxes. The primary items impacting the tax rate for the three months ended September 30, 2018 were $0.2 million relating to foreign exchange and a net increase to the company's valuation allowances of $3.7 million, consisting of $3.7 million increases in Canada due to losses and no changes in the United States for the period.

Income tax benefit for the three months ended September 30, 2017 was $15.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.9 million. The primary items impacting the tax rate for the three months ended September 30, 2017 were $3.5 million related to a net increase to our valuation allowances in Canada and $0.3 million of other permanent differences. These items were offset by $5.5 million relating to operating in higher tax rate jurisdictions and $1.3 million relating to foreign exchange.

Nine months ended September 30, 2018 compared to the nine months ended September 30, 2017

The following table provides our consolidated results of operations:

	Nine months ended September 30,			
	2018	2017	$ change	% change
Project revenue:				
Energy sales	$ 94.8	$ 113.6	$ (18.8)	(16.5)%
Energy capacity revenue	72.9	85.7	(12.8)	(14.9)%
Other	43.9	131.7	(87.8)	(66.7)%
	211.6	331.0	(119.4)	(36.1)%
Project expenses:				
Fuel	54.0	79.1	(25.1)	(31.7)%
Operations and maintenance	66.5	63.4	3.1	4.9 %
Depreciation and amortization	65.7	90.5	(24.8)	(27.4)%
	186.2	233.0	(46.8)	(20.1)%
Project other expense:				
Change in fair value of derivative instruments	3.6	(5.8)	9.4	NM
Equity in earnings (loss) of unconsolidated affiliates	33.7	(36.1)	69.8	NM
Interest expense, net	(1.4)	(6.6)	5.2	(78.8)%
Impairment	—	(57.3)	57.3	(100.0)%
Other income, net	6.7	0.1	6.6	NM
	42.6	(105.7)	148.3	NM
Project income (expense)	68.0	(7.7)	75.7	NM
Administrative and other expenses (income):				
Administration	17.9	17.6	0.3	1.7 %
Interest expense, net	40.7	49.5	(8.8)	(17.8)%
Foreign exchange (gain) loss	(9.1)	17.7	(26.8)	NM
Other expense, net	0.3	—	0.3	NM
	49.8	84.8	(35.0)	(41.3)%
Income (loss) from operations before income taxes	18.2	(92.5)	110.7	NM
Income tax expense (benefit)	7.7	(38.5)	46.2	NM
Net income (loss)	10.5	(54.0)	64.5	NM
Net (loss) income attributable to preferred shares of a subsidiary company	(1.6)	3.5	(5.1)	NM
Net income (loss) attributable to Atlantic Power Corporation	$ 12.1	$ (57.5)	$ 69.6	NM

	Nine months ended September 30, 2018				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 62.9	$ 10.1	$ 21.8	$ —	$ 94.8
Energy capacity revenue	41.5	22.9	8.5	—	72.9
Other	12.5	2.7	28.0	0.7	43.9
	116.9	35.7	58.3	0.7	211.6
Project expenses:					
Fuel	36.4	8.9	8.7	—	54.0
Operations and maintenance	27.6	20.4	18.1	0.4	66.5
Depreciation and amortization	27.3	14.3	24.0	0.1	65.7
	91.3	43.6	50.8	0.5	186.2
Project other income (expense):					
Change in fair value of derivative instruments	(0.8)	—	2.3	2.1	3.6
Equity in earnings of unconsolidated affiliates	28.1	5.6	—	—	33.7
Interest expense, net	(1.4)	—	—	—	(1.4)
Other income, net	—	6.7	—	—	6.7
	25.9	12.3	2.3	2.1	42.6
Project income	$ 51.5	$ 4.4	$ 9.8	$ 2.3	$ 68.0

	Nine months ended September 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 66.3	$ 24.6	$ 22.7	$ —	$ 113.6
Energy capacity revenue	38.8	38.9	8.0	—	85.7
Other	11.2	22.7	97.1	0.7	131.7
	116.3	86.2	127.8	0.7	331.0
Project expenses:					
Fuel	34.8	33.5	10.8	—	79.1
Operations and maintenance	25.2	18.9	19.5	(0.2)	63.4
Depreciation and amortization	26.9	22.7	40.6	0.3	90.5
	86.9	75.1	70.9	0.1	233.0
Project other income (expense):					
Change in fair value of derivative instruments	(3.3)	—	(5.4)	2.9	(5.8)
Equity in loss of unconsolidated affiliates	(35.9)	(0.2)	—	—	(36.1)
Interest expense, net	(6.6)	—	—	—	(6.6)
Impairment	—	(57.3)	—	—	(57.3)
Other income, net	—	—	0.1	—	0.1
	(45.8)	(57.5)	(5.3)	2.9	(105.7)
Project (loss) income	$ (16.4)	$ (46.4)	$ 51.6	$ 3.5	$ (7.7)

East U.S.

Project income for the nine months ended September 30, 2018 increased $67.9 million from the project loss for the comparable 2017 period primarily due to:

- increased project income of $48.0 million and $11.6 million at Chambers and Selkirk, respectively, primarily due to impairments of $47.1 million and $10.6 million, respectively, recorded in the comparable 2017 period;
- increased project income of $5.9 million at Piedmont primarily due to $5.0 million of lower interest expense resulting from the repayment of the project-level debt, in full, in 2017;
- increased project income of $4.6 million at Morris primarily due to higher energy and capacity energy

revenues than the comparable 2017 period; and

- increased project income of $5.6 million at Orlando primarily due to a $2.9 million increase in the change in fair value of derivatives and higher availability and contractual capacity rates than the comparable 2017 period.

These increases were partially offset by:

- decreased project income of $6.4 million at Curtis Palmer primarily due to lower water flows than the comparable 2017 period.

West U.S.

Project income for the nine months ended September 30, 2018 increased $50.8 million from the project loss for the comparable 2017 period primarily due to:

- increased project income of $17.6 million, $16.2 million and $10.4 million at Naval Station, North Island and NTC primarily due to $22.5 million, $13.5 million and $21.2 million long-lived asset impairments recorded for the comparable period in 2017, respectively; and

- increased project income of $5.8 million at Frederickson primarily due to lower planned maintenance expense than the comparable 2017 period.

These increases were partially offset by:

- decreased project income of $6.1 million at Manchief primarily due to a $7.5 million increase in maintenance expense from a turbine overhaul.

Canada

Project income for the nine months ended September 30, 2018 decreased $41.8 million from the comparable 2017 period primarily due to:

- decreased project income of $14.7 million at Kapuskasing primarily due to $29.4 million of revenue recorded related to the OEFC settlement in the comparable period in 2017 and the expiration of the enhanced dispatch contract, partially offset by a $13.5 million decrease in depreciation expense;

- decreased project income of $14.6 million at North Bay primarily due to $27.6 million of revenue recorded related to the OEFC settlement in the comparable period in 2017 and the expiration of the enhanced dispatch contract, partially offset by an $11.4 million decrease in depreciation expense;

- decreased project income of $10.8 million at Tunis primarily due to $6.9 million of revenue recorded related to the OEFC settlement in the comparable 2017 period and a $4.0 million increase in maintenance expense in preparation of commencing operation in October 2018;

- decreased project income of $2.7 million at Nipigon primarily due to a $13.2 million increase in amortization expense from accelerated amortization of the intangible PPA asset, partially offset by a positive $7.6 million change in the fair value of a gas purchase agreement, a $2.0 million increase in revenue due to a contractual rate increase and lower fuel expense than the comparable 2017 period; and

- decreased project income of $1.8 million at Williams Lake primarily due to a $5.0 million decrease in depreciation expense resulting from a $28.5 million long-lived asset impairment recorded in the fourth quarter of 2017, partially offset by a $1.3 million increase in maintenance expense.

These decreases were partially offset by:

- increased project income of $2.6 million at Mamquam primarily due to a maintenance outage in the comparable period in 2017.

Un-allocated Corporate

Project income for the nine months ended September 30, 2018 decreased $1.2 million primarily due to a $0.8 million decrease in change in fair value of interest swaps related to the senior secured credit facility.

Administrative and other expenses (income)

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

Administration

Administration expense did not change materially from the 2017 comparable period.

Interest expense, net

Interest expense decreased $8.8 million from the comparable 2017 period primarily due to lower outstanding debt balances than the comparable 2017 period, as well as a lower interest rate on our senior secured credit facility.

Foreign exchange gain

Foreign exchange gain increased $26.8 million to a $9.1 million gain in the nine months ended September 30, 2018 from a $17.7 million loss in the comparable 2017 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and convertible debentures). The Canadian dollar declined 3.1% against the U.S. dollar from December 31, 2017 to September 30, 2018, as compared to a 7.6% appreciation in the comparable 2017 period. Additionally, our Canadian dollar obligations increased from the comparable 2017 period as a result of the convertible debenture issuance in the first quarter of 2018.

Income tax expense

Income tax expense for the nine months ended September 30, 2018 was $7.7 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $4.7 million. The primary items impacting the tax rate for the nine months ended September 30, 2018 were a net increase to our valuation allowances of $4.5 million, consisting of $4.5 million of increases in Canada related to losses and no changes in the United States for the period. In addition, the rate was further impacted by $0.3 million relating to foreign exchange, $0.3 million relating to taxes and $0.1 million of other permanent differences. These items were partially offset by $1.3 million related to capital loss on intercompany notes and $0.9 million relating to changes in tax rates.

Income tax benefit for the nine months ended September 30, 2017 was $38.5 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $24.1 million. The primary items impacting the tax rate for the nine months ended September 30, 2017 were $1.5 million related to a net increase to our valuation allowances in Canada and $0.6 million relating to income taxes. These items were offset by $14.2 million relating to operating in higher tax rate jurisdictions and $2.3 million relating to foreign exchange.

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 nine months ended September 30, 2018. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in net Gigawatt hours (“net GWh”).

Generation

	Generation		
	Three months ended September 30,		
(in Net GWh)	2018	2017	% change 2018 vs. 2017
Segment			
East U.S.	573.9	662.7	(13.4)%
West U.S.	435.8	534.6	(18.5)%
Canada	224.9	239.7	(6.2)%
Total	1,234.6	1,437.0	(14.1)%

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Aggregate power generation for the three months ended September 30, 2018 decreased 14.1% from the comparable 2017 period primarily due to:

- decreased generation in the West U.S. segment primarily due to a combined 212.7 net GWh decrease in generation at Naval Station, North Island and NTC, which ceased operations in February 2018, partially offset by a 65.8 GWh net increase in generation at Manchief due to higher dispatch than the comparable 2017 period and a 48.9 net GWh increase in generation at Frederickson due to high demand; and

- decreased generation in the East U.S. segment primarily due to a 32.6 net GWh decrease in generation at Curtis Palmer due to lower water flows than the comparable 2017 period, a 20.0 net GWh decrease in generation at Piedmont due to a maintenance outage and a 14.7 net GWh decrease in generation at Selkirk, which was sold in November 2017.

	Generation		
	Nine months ended September 30,		
(in Net GWh)	2018	2017	% change 2018 vs. 2017
Segment			
East U.S.	1,834.0	1,866.2	(1.7)%
West U.S.	777.9	1,155.7	(32.7)%
Canada	723.1	698.2	3.6 %
Total	3,335.0	3,720.1	(10.4)%

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Aggregate power generation for the nine months ended September 30, 2018 decreased 10.4% from the comparable 2017 period primarily due to:

- decreased generation in the West U.S. segment primarily due to a combined 524.8 net GWh decrease in generation at Naval Station, North Island and NTC, which ceased operations in February 2018, partially offset by a 147.5 GWh increase in generation at Manchief due to higher dispatch than the comparable 2017 period; and

- decreased generation in the East U.S. segment primarily due to a 67.6 net GWh decrease in generation at Curtis Palmer due to lower water flows than the comparable 2017 period, a 29.2 net GWh decrease in generation at Selkirk, which was sold in November 2017, and a 20.7 net GWh decrease in generation at Piedmont due to a maintenance outage. These decreases were partially offset by a 47.4 net GWh increase at Orlando due to a maintenance outage performed in the comparable 2017 period and a 30.3 net GWh increase in generation at Morris due to higher dispatch than the comparable period in 2017.

These decreases were partially offset by:

- increased generation in the Canada segment primarily due to a 29.7 net GWh increase at Mamquam due to a 2017 maintenance outage and higher water flows than the comparable 2017 period.

Availability

	Availability Three months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Segment			
East U.S.	94.0 %	98.8 %	(4.9)%
West U.S. (1)	97.8 %	99.0 %	(1.2)%
Canada	90.2 %	97.5 %	(7.5)%
Weighted average	94.3 %	98.6 %	(4.4)%

(1) The San Diego projects, which ceased operations in February 2018, have been excluded from availability in both 2018 and 2017.

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Aggregate power availability for the three months ended September 30, 2018 decreased 4.4% from the comparable 2017 period primarily due to:

- decreased availability in the Canada segment primarily due to a maintenance outage at Moresby Lake in the 2018 period;
- decreased availability in the East U.S. segment primarily due to maintenance outages at Morris and Cadillac in the 2018 period; and
- decreased availability in the West U.S. segment primarily due to a maintenance outage at Koma in the 2018 period.

	Availability Nine months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Segment			
East U.S.	95.8 %	94.1 %	1.8 %
West U.S. (1)	94.6 %	89.9 %	5.2 %
Canada	95.4 %	91.8 %	3.9 %
Weighted average	95.4 %	92.9 %	2.7 %

(1) The San Diego projects, which ceased operations in February 2018, have been excluded from availability in both 2018 and 2017.

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Aggregate power availability for the nine months ended September 30, 2018 increased 2.7% from the comparable 2017 period primarily due to:

- increased availability in the West U.S. segment primarily due to maintenance outages at Frederickson in the comparable 2017 period, partially offset by decreased availability at Manchief due to a maintenance outage in the 2018 period;

- increased availability in the Canada segment primarily due to a maintenance outage at Mamquam in the comparable 2017 period partially offset by decreased availability at Moresby Lake due to a maintenance outage in the 2018 period; and

- increased availability in the East U.S. segment primarily due to maintenance outages at Kenilworth and Orlando in the comparable 2017 period and a shorter maintenance outage at Piedmont in 2018 than in the comparable 2017 period.

Supplementary Non-GAAP Financial Information

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

Project Adjusted EBITDA

	Three months ended September 30, 2018	Three months ended September 30, 2017	$ change 2018 vs 2017	Nine months ended September 30, 2018	Nine months ended September 30, 2017	$ change 2018 vs 2017
Net (loss) income	$ (4.7)	$ (33.7)	$ 29.0	$ 10.5	$ (54.0)	$ 64.5
Income tax expense (benefit)	3.6	(15.9)	19.5	7.7	(38.5)	46.2
(Loss) income from operations before income taxes	(1.1)	(49.6)	48.5	18.2	(92.5)	110.7
Administration	5.7	5.5	0.2	17.9	17.6	0.3
Interest expense, net	14.6	13.8	0.8	40.7	49.5	(8.8)
Foreign exchange (gain) loss	4.5	9.4	(4.9)	(9.1)	17.7	(26.8)
Other income, net	2.5	—	2.5	0.3	—	0.3
Project income (loss)	$ 26.2	$ (20.9)	$ 47.1	$ 68.0	$ (7.7)	$ 75.7
Reconciliation to Project Adjusted EBITDA						
Depreciation and amortization	25.0	36.6	(11.6)	78.0	105.6	(27.6)
Interest expense, net	(0.6)	2.5	(3.1)	2.7	8.0	(5.3)
Change in the fair value of derivative instruments	—	2.0	(2.0)	(3.5)	5.8	(9.3)
Impairment	—	57.3	(57.3)	—	57.3	(57.3)
Other income, net	(5.2)	(0.1)	(5.1)	(6.7)	57.6	(64.3)
Project Adjusted EBITDA	$ 45.4	$ 77.4	$ (32.0)	$ 138.5	$ 226.6	$ (88.1)
Project Adjusted EBITDA by segment						
East U.S.	25.5	30.6	(5.1)	89.8	86.8	3.0
West U.S.	11.5	21.7	(10.2)	16.9	41.5	(24.6)
Canada	8.3	24.6	(16.3)	31.5	97.3	(65.8)
Un-Allocated Corporate	0.1	0.5	(0.4)	0.3	1.0	(0.7)
Total	$ 45.4	$ 77.4	$ (32.0)	$ 138.5	$ 226.6	$ (88.1)

East U.S.

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

	Three months ended September 30, 2018	Three months ended September 30, 2017	% change 2018 vs. 2017
East U.S.			
Project Adjusted EBITDA	$ 25.5	$ 30.6	(17)%

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Project Adjusted EBITDA for the three months ended September 30, 2018 decreased $5.1 million from the comparable 2017 period primarily due to decreased Project Adjusted EBITDA of:

- $3.3 million at Curtis Palmer due to lower water flows than the comparable 2017 period;
- $1.2 million at Cadillac due to a $0.8 million decrease in revenue due to a maintenance outage in 2018; and
- $0.9 million at Kenilworth due to $0.7 million of increased maintenance expense from the comparable 2017 period.

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

- $0.8 million at Morris due to $0.9 million of increased revenue from a higher capacity price than the comparable 2017 period.

	Nine months ended September 30,		
	2018	2017	% change 2018 vs. 2017
East U.S.			
Project Adjusted EBITDA	$ 89.8	$ 86.8	3 %

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Project Adjusted EBITDA for the nine months ended September 30, 2018 increased $3.0 million from the comparable 2017 period primarily due to increased Project Adjusted EBITDA of:

- $6.2 million at Morris due to $5.6 million of increased revenue from higher capacity prices, higher merchant dispatch and higher steam and ancillary services than the comparable 2017 period;
- $2.6 million at Orlando due to higher availability and contractual capacity rates than the comparable 2017 period; and
- $1.0 million at Selkirk, which had a project loss in the comparable 2017 period and was sold in the fourth quarter of 2017.

These increases were partially offset by decreased Project Adjusted EBITDA of:

- $6.4 million at Curtis Palmer due to lower water flows than the comparable 2017 period; and
- $1.0 million at Cadillac due to a $0.2 million decrease in gross margin and $0.8 million of higher maintenance expense due to a maintenance outage in nine months ended September 30, 2018.

West U.S.

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

	Three months ended September 30,		
	2018	2017	% change 2018 vs 2017
West U.S.			
Project Adjusted EBITDA	$ 11.5	$ 21.7	(47)%

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Project Adjusted EBITDA for the three months ended September 30, 2018 decreased $10.2 million from the comparable 2017 period primarily due to decreased Project Adjusted EBITDA of:

- $4.5 million, $4.1 million and $2.6 million at Naval Station, North Island and NTC, respectively, which ceased operations in February 2018.

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

- $0.8 million at Manchief due to higher dispatch than the comparable 2017 period.

	Nine months ended September 30,		
	2018	2017	% change 2018 vs 2017
West U.S.			
Project Adjusted EBITDA	$ 16.9	$ 41.5	(59)%

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Project Adjusted EBITDA for the nine months ended September 30, 2018 decreased $24.6 million from the comparable 2017 period primarily due to decreased Project Adjusted EBITDA of:

- $8.8 million, $7.7 million and $5.2 million at Naval Station, North Island and NTC, respectively, which ceased operations in February 2018; and
- $6.1 million at Manchief due to a $7.4 million increase in maintenance expense from a turbine overhaul completed in the second quarter of 2018.

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

- $3.0 million at Frederickson primarily due to higher maintenance expense recorded in the comparable 2017 period.

Canada

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

	Three months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Canada			
Project Adjusted EBITDA	$ 8.3	$ 24.6	(66)%

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Project Adjusted EBITDA for the three months ended September 30, 2018 decreased $16.3 million from the comparable 2017 period primarily due to decreased Project Adjusted EBITDA of:

- $6.2 million and $5.1 million at Kapuskasing and North Bay, respectively, due to expiration of the enhanced dispatch agreements in December 2017 and the OEFC settlement received in the comparable 2017 period; and
- $5.0 million at Williams Lake primarily due to lower gross margin under the short-term contract extension that become effective in April 2018.

	Nine months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Canada			
Project Adjusted EBITDA	$ 31.5	$ 97.3	(68)%

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Project Adjusted EBITDA for the nine months ended September 30, 2018 decreased $65.8 million from the comparable 2017 period primarily due to decreased Project Adjusted EBITDA of:

- $28.2 million and $26.0 million at Kapuskasing and North Bay, respectively, due to the expiration of the enhanced dispatch agreements in December 2017 and the OEFC settlement received in December 2017;
- $10.8 million at Tunis due to $6.7 million of revenue recorded related to the OEFC settlement in the comparable 2017 period and higher maintenance expense incurred during 2018 in order to commence operations in October 2018; and
- $6.8 million at Williams Lake primarily due to lower gross margin under the short-term contract extension that became effective in April 2018, partially offset by cost reductions.

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

- $2.9 million at Nipigon primarily due to a contractual rate increase and lower fuel expense than the comparable 2017 period; and

- $2.6 million at Mamquam primarily due to higher water flows and the timing of maintenance expense relative to the comparable 2017 period.

Un-allocated Corporate

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

	Three months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Un-allocated Corporate			
Project Adjusted EBITDA	$ 0.1	$ 0.5	NM

Three months ended September 30, 2018 compared with three months ended September 30, 2017

Project Adjusted EBITDA for the three months ended September 30, 2018 did not change materially from the comparable 2017 period.

	Nine months ended September 30,		
	2018	2017	% change 2018 vs. 2017
Un-allocated Corporate			
Project Adjusted EBITDA	$ 0.3	$ 1.0	NM

Nine months ended September 30, 2018 compared with nine months ended September 30, 2017

Project Adjusted EBITDA for the nine months ended September 30, 2018 did not change materially from the comparable 2017 period.

Liquidity and Capital Resources

	September 30, 2018	December 31, 2017
Cash and cash equivalents	$ 57.6	$ 78.7
Restricted cash	0.3	6.2
Total	57.9	84.9
Revolving credit facility availability	123.0	119.5
Total liquidity	$ 180.9	$ 204.4

Overview

Our primary sources of liquidity are distributions from our projects and availability under our Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from June 30, 2019 to March 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See “Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities” in our Annual Report on Form 10-K for the year ended December 31, 2017.

We expect to reinvest approximately $35.2 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2018, of which $29.2 million has been incurred through September 30, 2018. Such investments are generally paid at the project level. See "Liquidity and Capital Resources—Capital and Maintenance Expenditures" in our Annual Report on Form 10-K for the year ended December 31, 2017. On July 27, 2018, we used $12.5 million of cash on-hand to acquire the remaining 50% partnership interest in Koma and buy-out the operation and maintenance contract from the prior owner. We do not expect any other material or unusual requirements for cash outflows in 2018 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,		
	2018	2017	Change
Net cash provided by operating activities	$ 97.8	$ 138.7	$ (40.9)
Net cash used in investing activities	(16.9)	(5.7)	(11.2)
Net cash used in financing activities	(107.9)	(97.0)	(10.9)

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, 2018, the net decrease in cash provided by operating activities of $40.9 million was primarily the result of the following:

- *Contract expirations* – the expiration of the enhanced dispatch contracts at our North Bay and Kapuskasing projects on December 31, 2017, as well as operations ceasing at our San Diego projects in February 2018, had a $57.1 million impact on cash flows from operations;

- *OEFC settlement* – we received approximately $25.6 million related to our settlement with the OEFC in the comparable 2017 period;

- *Major maintenance* – a planned major maintenance outage at our Manchief project had a $6 .1 million impact on cash flows from operations. Additionally, costs incurred to prepare our Tunis project for commercial operations had a $3.9 million impact on cash flows from operations;

- *Contract extension* – the energy purchase agreement extension at Williams Lake that became effective in April 2018 provides lower pass-through of costs than the previous contract. The project also had lower dispatch than the comparable 2017 period. These factors had a $6.8 million impact on cash flows provided by operating activities; and

- *Hydrological conditions* – lower water flows at our Curtis Palmer project had a $6.4 million impact on cash flows provided by operating activities.

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

- *Working capital* – changes in working capital resulted in a $34.6 million increase in cash flows from operating activities primarily due to a $29.2 million decrease in working capital at our Kapuskasing, North Bay and San Diego projects, which were not in operation at September 30, 2018.

- *Interest expense* – our interest payments were $13.9 million lower than the comparable 2017 period due to lower interest rates and outstanding principal on our senior secured credit facility, the repayment of the Epsilon Power Partners term facility, in full, in the second quarter of 2018 and the repayment of Piedmont's project-level debt, in full, in the fourth quarter of 2017;

- *Distributions from unconsolidated affiliates* – we received $6.5 million in higher distributions from our unconsolidated affiliates, primarily at our Frederickson ($2.9 million increase) and Orlando ($2.1 million increase) projects; and

- *Morris* – higher capacity prices, higher merchant dispatch and higher steam and ancillary services than the comparable 2017 period had a $6.2 million impact on cash flows from operations at Morris in the nine months ended September 30, 2018.

Investing Activities

For the nine months ended September 30, 2018, the net increase in cash used in investing activities of $11.2 million was primarily the result of the following:

- *Acquisition of Koma* – we paid $12.8 million, net of cash received, to acquire an additional 0.25% ownership of Koma in the second quarter of 2018 and the remaining 50% of Koma in the third quarter of 2018.

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

- *Capitalized plant additions* – capitalized plant additions were $4.2 million lower in the nine months ended September 30, 2018 than the comparable 2017 period.

Financing Activities

For the nine months ended September 30, 2018, the net increase in cash used in financing activities of $10.9 million was primarily the result of the following:

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

- *Preferred share repurchases* – we paid $8.0 million in the nine months ended September 30, 2018 to repurchase and cancel preferred shares as compared to $3.1 million in the comparative 2017 period;

- *Common share repurchases* – we paid $12.3 million in the nine months ended September 30, 2018 to repurchase and cancel common shares as compared to $0.2 million in the comparative 2017 period; and

- *Deferred financing costs* – we incurred $5.1 million of deferred financing costs related to the issuance of the Series E Debentures.

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

- *Convertible debenture issuance* – we received $92.2 million from the issuance of the Series E Debentures; and

- *Corporate and project-level debt repayments* – we made $6.8 million less principal payments than the comparable 2017 period.

Corporate Debt

The following table summarizes the maturities of our corporate debt at September 30, 2018:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2018	2019	2020	2021	2022	Thereafter
Senior secured term loan facility [(1)]	April 2023	3.87 % - 5.42 %	$ 470.0	$ 20.0	$ 65.0	$ 105.0	$ 80.0	$ 75.0	$ 125.0
MTNs	June 2036	5.95 %	162.2	—	—	—	—	—	162.2
Convertible Debenture	December 2019	6.00 %	19.1	—	19.1	—	—	—	—
Convertible Debenture	January 2025	6.00 %	88.8	—	—	—	—	—	88.8
Total Corporate Debt			$ 740.1	$ 20.0	$ 84.1	$ 105.0	$ 80.0	$ 75.0	$ 376.0

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

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, 2018. 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 October 31, 2018, all of our projects were in compliance with the covenants contained in project-level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but are not callable or subject to acceleration under the terms of their debt agreements.

The range of interest rates presented represents the rates in effect at September 30, 2018. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Maturity Date	Range of Interest Rates	Total Remaining Principal Repayments	2018	2019	2020	2021	2022	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.14 % - 6.38 %	$ 21.8	$ 0.8	$ 3.1	$ 3.1	$ 2.7	$ 3.3	$ 8.8
Total Consolidated Projects			21.8	0.8	3.1	3.1	2.7	3.3	8.8
Equity Method Projects:									
Chambers [(1)]	December 2019 and 2023	4.50 % - 5.00 %	42.9	—	5.2	7.8	8.8	10.1	11.0
Total Equity Method Projects			42.9	—	5.2	7.8	8.8	10.1	11.0
Total Project-Level Debt			$ 64.7	$ 0.8	$ 8.3	$ 10.9	$ 11.5	$ 13.4	$ 19.8

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

Uses of Liquidity

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

Capital and Maintenance Expenditures

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

We expect to reinvest approximately $1.8 million in 2018 (of which $1.4 million was reinvested in the nine months ended September 30, 2018) in our portfolio, including equity method investments, in the form of project capital expenditures, and incur $33.4 million of maintenance expenses (of which $27.8 million was incurred in the nine months ended September 30, 2018). Such investments are generally paid at the project level. See “Liquidity and Capital Resources—Capital and Maintenance Expenditures” in our Annual Report on Form 10-K for the year ended December 31, 2017. We do not expect any other material or unusual requirements for cash outflows for 2018 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 2018 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, 2018, 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, 2017.

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 Exchange Act as of the end of the period covered by this report, and they have concluded that these controls and procedures are effective.