the differences may be material. Certain statements included in this Quarterly Report on Form 10-Q may be considered “financial outlook” for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10-Q. These forward-looking statements are made as of the date of this Quarterly Report on Form 10-Q and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

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 PPAs, which seek to minimize exposure to changes in commodity prices. As of June 30, 2019, our portfolio consisted of seventeen operating projects with an aggregate electric generating capacity of approximately 1,598 megawatts (“MW”) on a gross ownership basis and approximately 1,252 MW on a net ownership basis. Fourteen of the projects are majority-owned by the Company. On July 31, 2019, we completed the acquisition of two biomass plants in South Carolina, increasing our generating capacity to 1,638 MW on a gross ownership basis and approximately 1,292 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 September 30, 2019 (Williams Lake) to November 18, 2043 (Allendale). 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 sixteen of our operating 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

South Carolina biomass plants acquisition

On July 31, 2019, we completed our acquisition of two biomass plants in South Carolina from EDF Renewables Inc. for $13 million. In September 2018, we made a $2.6 million down payment for the acquisition of the plants and paid the remaining $10.4 million due at closing from discretionary cash and cash equivalents. Due to the timing of the acquisition of the plants, preliminary opening balance sheet amounts and purchase accounting adjustments are still being prepared and the purchase price is subject to customary post-closing adjustments. The Allendale plant is located in Allendale, South Carolina and the Dorchester plant in Harleyville, South Carolina. Each of the plants has a capacity of 20 megawatts , and all of the output of the two plants is sold to Santee Cooper, a state-owned utility, under power purchase agreements that run to 2043.

PPA renewal

In July 2019, a subsidiary of Merck & Co., Inc. exercised the third of its three successive one-year extension options under the PPA for Kenilworth, extending the expiration date of our Kenilworth project's PPA from September 30, 2020 to September 30, 2021.

AltaGas acquisition

On May 14, 2019, we executed an agreement to acquire, for $20 million, the equity ownership interests held by AltaGas Power Holdings (U.S.) Inc. ("AltaGas") in two contracted biomass plants in North Carolina and Michigan. Craven County Wood Energy ("Craven") is a 48 megawatt (MW) biomass plant in North Carolina that has been in service since October 1990. We will acquire a 50% interest in the plant from AltaGas. The remaining 50% interest is held by CMS Energy. Craven County has a PPA with Duke Energy Carolinas that runs through December 2027. The plant burns wood waste, including wood chips, poultry litter, forestry residues, mill waste, bark and sawdust. Grayling Generating Station ("Grayling") is a 37 MW biomass plant in Michigan that has been in service since June 1992. We will acquire a 30% interest in the plant from AltaGas. The remaining interests are held by Fortistar (20%) and CMS Energy (50%). Grayling has a PPA with Consumers Energy, the utility subsidiary of CMS Energy, which runs through December 2027. The plant burns wood waste from local mills, forestry residues, mill waste and bark. Both plants are operated by an affiliate of CMS Energy. We expect to account for our ownership in Craven and Grayling under the equity method of accounting.

The acquisition is subject to the approval of the Federal Energy Regulatory Commission and customary third-party consents. We expect the transaction to close in the third quarter of 2019. The purchase will be funded from our discretionary cash.

Manchief sale agreement

On May 24, 2019, we executed an agreement to sell our Manchief power plant to Public Service Co. of Colorado ("PSCo") for $45.2 million, subject to working capital and other customary adjustments. PSCo, a subsidiary of Xcel Energy, Inc., is the current customer under the Manchief PPA. Proceeds of the sale are expected to be used to reduce the remaining principal amount of our senior secured term loan. Closing of the sale is expected to occur in May 2022, following the expiration of the PPA. Upon closing of the sale, the Company will enter into a guaranty agreement, under which it will agree to absolutely, unconditionally and irrevocably guarantee the full and prompt payment of all payment obligations of Manchief Holdings LLC under the agreement as and when they shall become due.

Convertible debenture redemption

On April 10, 2019, we redeemed, in full, the aggregate principal amount of Cdn$24.7 million of the outstanding Series D Debentures and paid accrued interest of Cdn$0.4 million.

OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of July 31, 2019, 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 %	100	Merchant	N/A	NR
					77	Equistar Chemicals, LP [(3)]	December 2034	BBB+ [(4)]
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	BBB+
Chambers [(1)]	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric [(5)]	March 2024	A-
					16	Chemours Co.	March 2024	BB
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2021 [(6)]	AA
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 [(7)]	A-
Allendale	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	November 2043	A+
Dorchester	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	October 2043	A+
West U.S. Segment								
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	May 2020 [(8)]	BBB
Manchief [(9)]	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 [(10)]	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 [(11)]	British Columbia	Biomass	66	100.00 %	66	British Columbia Hydro and Power Authority	September 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	AA
Tunis	Ontario	Natural Gas	37	100.00 %	37	Independent Electricity System Operator	October 2033	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) Equistar has the right under the PPA to take up to 77 MW, but on average has taken approximately 50 MW.

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

(5) 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.

(6) In July 2019, Merck exercised the third of its three successive one-year options under the PPA for Kenilworth, extending its expiration date from September 30, 2020 to September 30, 2021.

(7) 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 March 31, 2019, the facility has generated 7,895 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

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

(9) In May 2019, we entered into an agreement to sell Manchief to PSCo following the expiration of the PPA in April 2022 for $45.2 million subject to working capital and other customary adjustments.

(10) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021 and every five-year anniversary thereafter.

(11) The Williams Lake PPA with BC Hydro is scheduled to expire on September 30, 2019. Discussions with BC Hydro on a potential long-term contract are continuing.

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) We are in the process of decommissioning all three sites and expect to complete the process in 2020, which is a requirement of our land use agreements with the Navy.

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, 2019 and 2018, which are analyzed in greater detail below:

	Three months ended June 30, 2019	Three months ended June 30, 2018	Six months ended June 30, 2019	Six months ended June 30, 2018
Project revenue	$ 71.3	$ 66.2	$ 144.3	$ 146.2
Project income	21.7	13.6	52.2	41.8
Net income (loss) attributable to Atlantic Power Corporation	1.2	(0.6)	10.1	15.2
Net cash provided by operating activities	38.9	28.1	68.1	78.4
Net cash (used in) provided by investing activities	(0.1)	(1.3)	1.1	(2.4)
Net cash used in financing activities	(41.3)	(32.5)	(66.8)	(78.2)
Earnings (loss) per share attributable to Atlantic Power Corporation—basic	0.01	(0.01)	0.09	0.13
Earnings (loss) per share attributable to Atlantic Power Corporation—diluted	0.01	(0.01)	0.09	0.13
Project Adjusted EBITDA (1)	50.8	39.8	104.5	93.2

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

Project revenue increased by $5.1 million to $71.3 million in the three months ended June 30, 2019 from $66.2 million in the three months ended June 30, 2018. The primary drivers of the increase are as follows:

- *Curtis Palmer* – higher water flows resulted in a $5.8 million increase in revenue from the comparable 2018 period;

- *Tunis* - the project commenced its restart in October 2018 and recorded $1.1 million of revenue in the three months ended June 30, 2019; and

- *Koma Kulshan* – the project was consolidated in July 2018 and recorded $1.1 million of revenue in the three months ended June 30, 2019.

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

- *Kenilworth* - decrease of steam revenue by $1.1 million from the comparable 2018 period ; and

- *Williams Lake* – the extension of the energy purchase agreement became effective in April 2018, and the change in terms resulted in a revenue decrease of $0.7 million in the three months ended June 30, 2019.

Consolidated project income increased by $8.1 million to $21.7 million in the three months ended June 30, 2019 from $13.6 million in the three months ended June 30, 2018. The primary drivers of the increase are as follows:

- *Project revenue* – project revenue increased $5.1 million as discussed above;

- *Operation and maintenance expenses* – operation and maintenance expenses decreased by $8.6 million primarily due to a decrease of $7.4 million of maintenance expense at our Manchief project where a gas turbine overhaul was performed in the comparable 2018 period and a decrease of $1.0 million of maintenance expense at our Tunis project where costs were incurred in the comparable period in preparation for the commencement of its commercial operation; and

- *Depreciation and amortization expense* – depreciation and amortization expense decreased by $4.9 million from the comparable 2018 period primarily due to a decrease of $5.3 million at our Nipigon project resulting from the PPA intangible asset being fully amortized in 2018.

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

- *Derivative Instruments* – the fair value of our derivative instruments decreased $6.8 million from the comparable 2018 period.

Project revenue decreased by $1.9 million to $144.3 million in the six months ended June 30, 2019 from $146.2 million in the six months ended June 30, 2018. The primary drivers of the decrease are as follows:

- *San Diego projects* – the Naval Station, NTC and North Island projects ceased operations in February 2018. This resulted in a $7.4 million decrease in project revenue in 2019;

- *Williams Lake* – the extension of the energy purchase agreement 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 2018 period. These factors resulted in a $4.9 million decrease in project revenue; and

- *Kenilworth* – decrease of steam revenue by $1.9 million from the comparable 2018 period.

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

- *Curtis Palmer* – higher water flows resulted in a $8.6 million increase in revenue from the comparable 2018 period;

- *Tunis* – the project commenced its restart in October 2018 and recorded $2.2 million of revenue in the six months ended June 30, 2019; and

- *Koma Kulshan* - the project was consolidated in July 2018 and recorded $1.5 million of revenue in the six months ended June 30, 2019.

Consolidated project income increased by $10.4 million to $52.2 million in the six months ended June 30, 2019 from $41.8 million in the six months ended June 30, 2018. The primary drivers of the increase are as follows:

- *Operation and maintenance expenses* – operation and maintenance expenses decreased by $13.4 million from the comparable 2018 period primarily due to a decrease of $7.4 million of maintenance expense at our Manchief project where a turbine overhaul was performed in the comparable 2018 period and a decrease of $3.3 million of maintenance expense at our Tunis project where costs were incurred in the comparable 2018 period in preparation for the commencement of its commercial operation;

- *Depreciation and amortization expense* – depreciation and amortization expense decreased by $12.4 million from the comparable 2018 period primarily due to a decrease of $10.8 million at our Nipigon project resulting from the PPA intangible asset being fully amortized in 2018 and a $2.6 million decrease at the San Diego projects, which ceased operations in February 2018; and

- *Fuel expense* – fuel expense decreased $1.4 million from the comparable 2018 period primarily due to a $4.2 million decrease at the San Diego projects, which ceased operations in February 2018, partially offset by $1.0 million of increased fuel expense at our Oxnard project due to higher fuel cost.

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

- *Project revenue* – project revenue decreased $1.9 million as discussed above; and

- *Derivative Instruments* – the fair value of our derivative instruments decreased $12.9 million from the comparable 2018 period.

A detailed discussion of project income by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 52.

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 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, 2019 compared to the three months ended June 30, 2018

The following table provides our consolidated results of operations:

	Three months ended June 30, 2019	2018	$ change	% change
Project revenue:				
Energy sales	$ 36.5	$ 31.4	$ 5.1	16.2 %
Energy capacity revenue	31.6	23.3	8.3	35.6 %
Other	3.2	11.5	(8.3)	(72.2)%
	71.3	66.2	5.1	7.7 %
Project expenses:				
Fuel	15.8	15.0	0.8	5.3 %
Operations and maintenance	18.6	27.2	(8.6)	(31.6)%
Depreciation and amortization	16.1	21.0	(4.9)	(23.3)%
	50.5	63.2	(12.7)	(20.1)%
Project other income (expense):				
Change in fair value of derivative instruments	(7.0)	(0.2)	(6.8)	NM [(1)]
Equity in earnings of unconsolidated affiliates	9.4	11.2	(1.8)	(16.1)%
Interest expense, net	(0.2)	(0.4)	0.2	(50.0)%
Other expense, net	(1.3)	—	(1.3)	NM
	0.9	10.6	(9.7)	(91.5)%
Project income	21.7	13.6	8.1	59.6 %
Administrative and other expenses:				
Administration	5.0	6.2	(1.2)	(19.4)%
Interest expense, net	11.0	11.1	(0.1)	(0.9)%
Foreign exchange loss (gain)	4.9	(5.4)	10.3	NM
Other income, net	(3.7)	(0.2)	(3.5)	NM
	17.2	11.7	5.5	47.0 %
Income from operations before income taxes	4.5	1.9	2.6	NM
Income tax expense	1.6	0.9	0.7	77.8 %
Net income	2.9	1.0	1.9	NM
Net income attributable to preferred shares of a subsidiary company	1.7	1.6	0.1	6.2 %
Net income (loss) attributable to Atlantic Power Corporation	$ 1.2	$ (0.6)	$ 1.8	NM

(1) NM is defined as "not meaningful" and includes changes greater than 100%.

	Three months ended June 30, 2019 East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 26.4	$ 3.0	$ 7.1	$ —	$ 36.5
Energy capacity revenue	14.1	6.6	10.9	—	31.6
Other	2.5	(0.3)	0.8	0.2	3.2
	43.0	9.3	18.8	0.2	71.3
Project expenses:					
Fuel	10.9	1.7	3.2	—	15.8
Operations and maintenance	9.9	3.4	5.4	(0.1)	18.6
Depreciation and amortization	9.1	4.2	2.8	—	16.1
	29.9	9.3	11.4	(0.1)	50.5
Project other income (expense):					
Change in fair value of derivative instruments	(2.4)	—	—	(4.6)	(7.0)
Equity in earnings of unconsolidated affiliates	8.2	1.2	—	—	9.4
Interest (expense) income, net	(0.3)	0.1	—	—	(0.2)
Other expense, net	—	(1.3)	—	—	(1.3)
	5.5	—	—	(4.6)	0.9
Project income (loss)	$ 18.6	$ —	$ 7.4	$ (4.3)	$ 21.7

	Three months ended June 30, 2018				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 21.6	$ 1.7	$ 8.1	$ —	$ 31.4
Energy capacity revenue	13.6	6.8	2.9	—	23.3
Other	3.8	(0.2)	7.7	0.2	11.5
	39.0	8.3	18.7	0.2	66.2
Project expenses:					
Fuel	10.5	1.4	3.1	—	15.0
Operations and maintenance	9.5	11.1	6.6	—	27.2
Depreciation and amortization	9.1	3.9	8.0	—	21.0
	29.1	16.4	17.7	—	63.2
Project other income (expense):					
Change in fair value of derivative instruments	(0.5)	—	0.2	0.1	(0.2)
Equity in earnings of unconsolidated affiliates	9.4	1.8	—	—	11.2
Interest expense, net	(0.4)	—	—	—	(0.4)
	8.5	1.8	0.2	0.1	10.6
Project income (loss)	$ 18.4	$ (6.3)	$ 1.2	$ 0.3	$ 13.6

East U.S.

Project income for the three months ended June 30, 2019 increased $0.2 million from the comparable 2018 period primarily due to:

- increased project income of $5.9 million at Curtis Palmer primarily due to higher water flows than the comparable 2018 period.

This increase was partially offset by:

- decreased project income of $1.7 million at Chambers primarily due to lower energy and steam sales and lower prices on excess energy than the comparable 2018 period;
- decreased project income of $1.5 million at Orlando primarily due to a $1.9 million decrease in the fair value of natural gas swaps, partially offset by higher availability;
- decreased project income of $1.2 million at Cadillac primarily due to a $0.6 million increase in fuel expense due to lower fuel reimbursement than the comparable 2018 period and a $0.6 million decrease in project revenue due to lower dispatch than the comparable 2018 period; and
- decreased project income of $0.4 million at Piedmont primarily due to a $0.5 million increase in maintenance expense for boiler repairs.

West U.S.

Project income for the three months ended June 30, 2019 increased $6.3 million from a project loss in the comparable 2018 period primarily due to:

- increased project income of $7.4 million at Manchief primarily due to a $7.4 million decrease in maintenance expense from a turbine overhaul in the comparable 2018 period.

Canada

Project income for the three months ended June 30, 2019 increased $6.2 million from the comparable 2018 period primarily due to:

- increased project income of $5.1 million at Nipigon primarily due to a $5.3 million decrease in amortization expense from accelerated amortization of the intangible PPA asset in the comparable 2018 period; and

- increased project income of $1.9 million at Tunis primarily due to a $1.0 million decrease in maintenance expense in preparation for commencing operations in October 2018 and a $1.1 million increase in project revenue.

These increases were partially offset by:

- decreased project income of $0.6 million at Mamquam primarily due to lower water flows than the comparable 2018 period.

Un-allocated Corporate

Project income for the three months ended June 30, 2019 decreased $4.6 million from the comparable 2018 period due to the decrease in the fair value of interest rate swap agreements 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 are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, treasury function, costs of being a public registrant, costs to develop or acquire future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate taxes. Significant non-cash items that impact Administrative and other expenses (income), and that are subject to potentially significant fluctuations include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

Administration

Administration expense decreased by $1.2 million to $5.0 million in the three months ended June 30, 2019 from $6.2 million in the comparable 2018 period primarily due to $0.6 million of lower professional services fees expense.

Interest expense, net

Interest expense did not change materially from the comparable 2018 period.

Foreign exchange loss (gain)

Foreign exchange loss increased by $10.3 million to a $4.9 million loss in the three months ended June 30, 2019 from a $5.4 million gain in the comparable 2018 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and convertible debentures). The Canadian dollar appreciated 2.1% against the U.S. dollar from March 31, 2019 to June 30, 2019, as compared to a 2.1% depreciation in the comparable 2018 period.

Other income, net

Other income increased by $3.5 million from the comparable 2018 period primarily due to a $2.7 million increase in the fair value of the convertible debenture conversion option.

Income tax expense

Income tax expense for the three months ended June 30, 2019 was $1.6 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $1.2 million. The primary items impacting the tax rate for the three months ended June 30, 2019 was a net increase to the Company's valuation allowances of $1.5 million, consisting of $3.7 million increases in Canada and $2.2 million decreases in the United States due to the utilization of net operating losses. In addition, the rate was further impacted by $0.4 million relating to withholding and state taxes and $0.2 million of other permanent differences. These items were partially offset by $1.7 million relating to foreign exchange.

Income tax expense for the three months ended June 30, 2018 was $0.9 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.5 million. The primary items impacting the tax rate for the three months ended June 30, 2018 were $0.3 million relating to foreign exchange and $0.2 million of other permanent differences. These items were partially offset by a net decrease to our valuation allowances of $0.1 million, consisting of $0.1 million decreases in Canada due to income and no changes in the United States for the period.

Six months ended June 30, 2019 compared to the six months ended June 30, 2018

The following table provides our consolidated results of operations:

	Six months ended June 30,			
	2019	2018	$ change	% change
Project revenue:				
Energy sales	$ 73.5	$ 69.8	$ 3.7	5.3 %
Energy capacity revenue	61.8	43.4	18.4	42.4 %
Other	9.0	33.0	(24.0)	(72.7)%
	144.3	146.2	(1.9)	(1.3)%
Project expenses:				
Fuel	35.8	37.2	(1.4)	(3.8)%
Operations and maintenance	35.1	48.5	(13.4)	(27.6)%
Depreciation and amortization	32.3	44.7	(12.4)	(27.7)%
	103.2	130.4	(27.2)	(20.9)%
Project other expense:				
Change in fair value of derivative instruments	(9.4)	3.5	(12.9)	NM
Equity in earnings of unconsolidated affiliates	22.3	23.5	(1.2)	(5.1)%
Interest expense, net	(0.6)	(1.0)	0.4	(40.0)%
Other expense, net	(1.2)	—	(1.2)	NM
	11.1	26.0	(14.9)	(57.3)%
Project income	52.2	41.8	10.4	24.9 %
Administrative and other expenses (income):				
Administration	11.8	12.2	(0.4)	(3.3)%
Interest expense, net	22.1	26.1	(4.0)	(15.3)%
Foreign exchange loss (gain)	9.9	(13.6)	23.5	NM
Other expense (income), net	0.9	(2.2)	3.1	NM
	44.7	22.5	22.2	98.7 %
Income from operations before income taxes	7.5	19.3	(11.8)	(61.1)%
Income tax expense	2.2	4.2	(2.0)	(47.6)%
Net income	5.3	15.1	(9.8)	(64.9)%
Net loss attributable to preferred shares of a subsidiary company	(4.8)	(0.1)	(4.7)	NM
Net income attributable to Atlantic Power Corporation	$ 10.1	$ 15.2	$ (5.1)	(33.6)%

	Six months ended June 30, 2019				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 53.2	$ 5.9	$ 14.4	$ —	$ 73.5
Energy capacity revenue	26.5	11.6	23.7	—	61.8
Other	7.3	(0.4)	1.6	0.5	9.0
	87.0	17.1	39.7	0.5	144.3
Project expenses:					
Fuel	24.6	3.6	7.6	—	35.8
Operations and maintenance	17.5	7.1	10.2	0.3	35.1
Depreciation and amortization	18.2	8.5	5.6	—	32.3
	60.3	19.2	23.4	0.3	103.2
Project other income (expense):					
Change in fair value of derivative instruments	(2.2)	—	(0.5)	(6.7)	(9.4)
Equity in earnings of unconsolidated affiliates	18.7	3.6	—	—	22.3
Interest (expense) income, net	(0.7)	0.1	—	—	(0.6)
Other income (expense), net	—	(1.2)	—	—	(1.2)
	15.8	2.5	(0.5)	(6.7)	11.1
Project income (loss)	$ 42.5	$ 0.4	$ 15.8	$ (6.5)	$ 52.2

	Six months ended June 30, 2018				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 47.0	$ 6.8	$ 16.0	$ —	$ 69.8
Energy capacity revenue	24.9	12.7	5.8	—	43.4
Other	8.7	2.4	21.4	0.5	33.0
	80.6	21.9	43.2	0.5	146.2
Project expenses:					
Fuel	24.1	6.8	6.3	—	37.2
Operations and maintenance	17.8	16.7	13.7	0.3	48.5
Depreciation and amortization	18.2	10.3	16.1	0.1	44.7
	60.1	33.8	36.1	0.4	130.4
Project other income (expense):					
Change in fair value of derivative instruments	(0.2)	—	1.4	2.3	3.5
Equity in earnings of unconsolidated affiliates	19.8	3.7	—	—	23.5
Interest expense, net	(1.0)	—	—	—	(1.0)
	18.6	3.7	1.4	2.3	26.0
Project income (loss)	$ 39.1	$ (8.2)	$ 8.5	$ 2.4	$ 41.8

East U.S.

Project income for the six months ended June 30, 2019 increased $3.4 million from the comparable 2018 period primarily due to:

- increased project income of $8.6 million at Curtis Palmer primarily due to higher water flows than the comparable 2018 period; and

This increase was partially offset by:

- decreased project income of $2.2 million at Chambers primarily due to lower energy and steam sales and lower prices on excess energy than the comparable 2018 period;

- decreased project income of $1.1 million at Cadillac primarily due to a $0.7 million increase in fuel expense due to lower fuel reimbursement than the comparable 2018 period and a $0.5 million decrease in energy sales due to lower dispatch than the comparable 2018 period;

- decreased project income of $0.6 million at Orlando primarily due to a $1.9 million decrease in the fair value of natural gas swaps, partially offset by capacity rate escalation under its PPA; and

- decreased project income of $0.6 million at Piedmont due to a $0.6 million increase in maintenance expense for boiler repairs.

West U.S.

Project income for the six months ended June 30, 2019 increased $8.6 million from a project loss in the comparable 2018 period primarily due to:

- increased project income of $7.9 million at Manchief primarily due to a $7.4 million decrease in maintenance expense from a turbine overhaul in the comparable 2018 period; and

- increased project income of $0.4 million, $0.7 million and $0.5 million at Naval Station, NTC and North Island, which ceased operations in February 2018 and incurred project loss in the comparable 2018 period.

These increases were partially offset by:

- decreased project income of $1.1 million at Oxnard due to a $0.8 million increase in maintenance expense for turbine maintenance.

Canada

Project income for the six months ended June 30, 2019 increased $7.3 million from the comparable 2018 period primarily due to:

- increased project income of $9.2 million at Nipigon primarily due to a $10.8 million decrease in amortization expense from accelerated amortization of the intangible PPA asset in the comparable 2018 period; and

- increased project income of $5.2 million at Tunis primarily due to a $3.3 million decrease in maintenance expense in preparation for commencing operations in October 2018 and a $2.2 million increase in project revenue.

These increases were partially offset by:

- decreased project income of $4.8 million at Williams Lake primarily due to the extension of the energy purchase agreement that 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 2018 period. These factors resulted in a $4.9 million decrease in project revenue;

- decreased project income of $1.1 million at Mamquam primarily due to lower water flows than the comparable 2018 period; and

- decreased project income of $0.7 million at Calstock due to higher fuel prices than the comparable 2018 period.

Un-allocated Corporate

Project income for the six months ended June 30, 2019 decreased $8.9 million from the comparable 2018 period primarily due to a $9.0 million decrease in the fair value of interest rate swap agreements 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 are 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 for the six months ended June 30, 2019 did not change materially from the six months ended June 30, 2018.

Interest expense, net

Interest expense decreased by $4.0 million to $22.1 million in the six months ended June 30, 2019 from $26.1 million in the comparable period in 2018, primarily due to lower outstanding debt balances than the comparable 2018 period, as well as a lower interest rate on our senior secured credit facility.

Foreign exchange loss (gain)

Foreign exchange loss increased by $23.5 million to a $9.9 million loss in the six months ended June 30, 2019 from a $13.6 million gain in the comparable 2018 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and convertible debentures). The Canadian dollar appreciated 4.1% against the U.S. dollar from December 31, 2018 to June 30, 2019, as compared to a 2.0% depreciation in the comparable 2018 period.

Other expense, net

Other expense increased by $3.1 million from $2.2 million of other income in the comparable 2018 period primarily due to a $4.2 million decrease in the fair value of the convertible debenture conversion option.

Income tax expense

Income tax expense for the six months ended June 30, 2019 was $2.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $2.0 million. The primary items impacting the tax rate for the six months ended June 30, 2019 were $0.8 million related to withholding and state taxes and $0.3 million of other permanent differences. These items were partially offset by $0.9 million relating to foreign exchange.

Income tax expense for the six months ended June 30, 2018 was $4.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $5.0 million. The primary items impacting the tax rate for the six months ended June 30, 2018 were a net increase to our valuation allowances of $0.8 million, consisting of $0.8 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 of taxes and $0.3 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.

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, 2019. 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 June 30,		
(in Net GWh)	2019	2018	% change 2019 vs. 2018
Segment			
East U.S.	624.7	603.9	3.4 %
West U.S.	166.3	98.9	68.1 %
Canada	268.1	277.1	(3.2)%
Total	1,059.1	979.9	8.1 %

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Aggregate power generation for the three months ended June 30, 2019 increased 8.1% from the comparable 2018 period primarily due to:

- increased generation in the West U.S. segment primarily due to a 70.4 net GWh increase in generation at Frederickson due to higher dispatch than the comparable 2018 period; and
- increased generation in the East U.S. segment primarily due to a 42.6 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable 2018 period.

These increases were partially offset by:

- decreased generation in the Canada segment primarily due to an 11.5 net GWh decrease in generation at Mamquam due to lower water flows.

	Generation Six months ended June 30,		
(in Net GWh)	2019	2018	% change 2019 vs. 2018
Segment			
East U.S.	1,274.9	1,260.1	1.2 %
West U.S.	473.9	342.2	38.5 %
Canada	482.4	498.2	(3.2)%
Total	2,231.2	2,100.5	6.2 %

Six months ended June 30, 2019 compared with six months ended June 30, 2018

Aggregate power generation for the six months ended June 30, 2019 increased 6.2% from the comparable 2018 period primarily due to:

- increased generation in the West U.S. segment primarily due to a 185.5 net GWh increase in generation at Frederickson due to higher dispatch than the comparable 2018 period and a 40.2 net GWh increase in generation at Manchief due to higher dispatch than the comparable 2018 period, partially offset by a combined 95.5 net GWh decrease in generation at Naval Station, NTC and North Island, which ceased operations in February 2018; and

- increased generation in the East U.S. segment primarily due to a 62.5 GWh increase in generation at Curtis Palmer due to higher water flows than the comparable 2018 period, partially offset by an 18.9 GWh decrease in generation at Chambers due to lower pricing.

These increases were partially offset by:

- decreased generation in the Canada segment primarily due to a 22.9 net GWh decrease in generation at Mamquam due to lower water flows.

Availability

	Availability Three months ended June 30,		
	2019	**2018**	**% change 2019 vs. 2018**
Segment			
East U.S.	96.7 %	95.3 %	1.4 %
West U.S. (1)	89.4 %	85.2 %	4.2 %
Canada	93.3 %	96.4 %	(3.1)%
Weighted average	94.6 %	93.4 %	1.2 %

(1) The San Diego projects, which ceased operations in February 2018, have been excluded from availability in both 2019 and 2018.

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Aggregate power availability for the three months ended June 30, 2019 increased 1.2% from the comparable 2018 period primarily due to:

- increased availability in the West U.S. segment primarily due to a maintenance outage at Manchief in the comparable 2018 period, partially offset by a maintenance outage at Oxnard in the 2019 period; and

- increased availability in the East U.S. segment primarily due to a maintenance outage at Kenilworth in the comparable 2018 period and a maintenance outage at Chambers in the comparable 2018 period.

These increases were partially offset by:

- decreased availability in the Canada segment primarily due to a maintenance outage at Moresby Lake in the 2019 period.

	Availability Six months ended June 30,		
	2019	**2018**	**% change 2019 vs. 2018**
Segment			
East U.S.	97.6 %	96.7 %	0.9 %
West U.S. (1)	93.1 %	93.3 %	(0.2)%
Canada	95.2 %	98.1 %	(2.9)%
Weighted average	96.2 %	96.0 %	0.2 %

Six months ended June 30, 2019 compared with six months ended June 30, 2018

There was no material change in aggregate power availability for the six months ended June 30, 2019 as compared to the 2018 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 June 30, 2019	Three months ended June 30, 2018	$ change 2019 vs 2018	Six months ended June 30, 2019	Six months ended June 30, 2018	$ change 2019 vs 2018
Net income	$ 2.9	$ 1.0	$ 1.9	$ 5.3	$ 15.1	$ (9.8)
Income tax expense	1.6	0.9	0.7	2.2	4.2	(2.0)
Income from operations before income taxes	4.5	1.9	2.6	7.5	19.3	(11.8)
Administration	5.0	6.2	(1.2)	11.8	12.2	(0.4)
Interest expense, net	11.0	11.1	(0.1)	22.1	26.1	(4.0)
Foreign exchange loss (gain)	4.9	(5.4)	10.3	9.9	(13.6)	23.5
Other (income) expense, net	(3.7)	(0.2)	(3.5)	0.9	(2.2)	3.1
Project income	$ 21.7	$ 13.6	$ 8.1	$ 52.2	$ 41.8	$ 10.4
Reconciliation to Project Adjusted EBITDA						
Depreciation and amortization	20.1	25.1	(5.0)	40.2	53.1	(12.9)
Interest expense, net	0.8	0.9	(0.1)	1.5	1.9	(0.4)
Change in the fair value of derivative instruments	7.0	0.2	6.8	9.4	(3.6)	13.0
Other expense, net	1.2	—	1.2	1.2	—	1.2
Project Adjusted EBITDA	$ 50.8	$ 39.8	$ 11.0	$ 104.5	$ 93.2	$ 11.3
Project Adjusted EBITDA by segment						
East U.S.	33.4	31.2	2.2	69.4	64.4	5.0
West U.S.	6.9	(0.7)	7.6	13.0	5.4	7.6
Canada	10.2	9.0	1.2	21.9	23.2	(1.3)
Un-Allocated Corporate	0.3	0.3	—	0.2	0.2	—
Total	$ 50.8	$ 39.8	$ 11.0	$ 104.5	$ 93.2	$ 11.3

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, 2019	Three months ended June 30, 2018	% change 2019 vs. 2018
East U.S.			
Project Adjusted EBITDA	$ 33.4	$ 31.2	7 %

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Project Adjusted EBITDA for the three months ended June 30, 2019 increased $2.2 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $5.9 million at Curtis Palmer due to higher water flows than the comparable 2018 period.

This increase was partially offset by:

- $1.7 million at Chambers due to lower energy and steam demands and lower prices on excess energy than the comparable 2018 period; and

- $1.2 million at Cadillac due to lower fuel reimbursement and lower dispatch than the comparable 2018 period.

	Six months ended June 30,		
	2019	2018	% change 2019 vs. 2018
East U.S.			
Project Adjusted EBITDA	$ 69.4	$ 64.4	8 %

Six months ended June 30, 2019 compared with six months ended June 30, 2018

Project Adjusted EBITDA for the six months ended June 30, 2019 increased $5.0 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $8.6 million at Curtis Palmer due to higher water flows than the comparable 2018 period; and

- $1.4 million at Orlando due to capacity rate escalation under the PPA and lower maintenance expense than the comparable 2018 period.

These increases were partially offset by:

- $2.3 million at Chambers due to lower energy and steam demands and lower prices on excess energy than the comparable 2018 period; and

- $1.3 million at Cadillac due to lower fuel reimbursement and lower dispatch than the comparable 2018 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,		
	2019	2018	% change 2019 vs 2018
West U.S.			
Project Adjusted EBITDA	$ 6.9	$ (0.7)	NM

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Project Adjusted EBITDA for the three months ended June 30, 2019 increased $7.6 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $7.4 million at Manchief due to a turbine overhaul in the comparable 2018 period.

This increase was partially offset by:

- $1.0 million at Oxnard due to turbine maintenance during the three months ended June 30, 2019.

	Six months ended June 30,		
	2019	2018	% change 2019 vs 2018
West U.S.			
Project Adjusted EBITDA	$ 13.0	$ 5.4	141 %

Six months ended June 30, 2019 compared with six months ended June 30, 2018

Project Adjusted EBITDA for the six months ended June 30, 2019 increased $7.6 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $7.9 million at Manchief due to a turbine overhaul in the comparable 2018 period.

This increase was partially offset by:

- $1.2 million at Oxnard due to turbine maintenance during the six months ended June 30, 2019.

Canada

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

	Three months ended June 30,		
	2019	2018	% change 2019 vs. 2018
Canada			
Project Adjusted EBITDA	$ 10.2	$ 9.0	13 %

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Project Adjusted EBITDA for the three months ended June 30, 2019 increased $1.2 million from the comparable 2018 period primarily due to increased Project Adjusted EBITDA of:

- $2.2 million at Tunis due to a $1.0 million decrease in maintenance expense in preparation for commencing operations in October 2018 and a $1.1 million increase in project revenue.

	Six months ended June 30,		
	2019	2018	% change 2019 vs. 2018
Canada			
Project Adjusted EBITDA	$ 21.9	$ 23.2	(6)%

Six months ended June 30, 2019 compared with six months ended June 30, 2018

Project Adjusted EBITDA for the six months ended June 30, 2019 decreased $1.3 million from the comparable 2018 period primarily due to decreased Project Adjusted EBITDA of:

- $4.9 million at Williams Lake primarily due to the extension of the energy purchase agreement that 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 2018 period;

- $1.2 million at Mamquam due to lower water flows than the comparable 2018 period; and

- $0.8 million at Calstock primarily due to higher fuel prices than the comparable 2018 period.

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

- $5.7 million at Tunis due to a $3.3 million decrease in maintenance expense in preparation for commencing operations in October 2018 and a $2.2 million increase in project revenue.

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,		
	2019	2018	% change 2019 vs. 2018
Un-allocated Corporate			
Project Adjusted EBITDA	$ 0.3	$ 0.3	— %

Three months ended June 30, 2019 compared with three months ended June 30, 2018

Project Adjusted EBITDA for the three months ended June 30, 2019 did not change materially from the comparable 2018 period.

	Six months ended June 30,		
	2019	2018	% change 2019 vs. 2018
Un-allocated Corporate			
Project Adjusted EBITDA	$ 0.2	$ 0.2	— %

Six months ended June 30, 2019 compared with six months ended June 30, 2018

Project Adjusted EBITDA for the six months ended June 30, 2019 did not change materially from the comparable 2018 period.

Liquidity and Capital Resources

	June 30, 2019	December 31, 2018
Cash and cash equivalents	$ 71.4	$ 68.3
Restricted cash	1.4	2.1
Total	72.8	70.4
Revolving credit facility availability	123.0	123.1
Total liquidity	$ 195.8	$ 193.5

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 September 30, 2019 (Williams Lake) to November 18, 2043 (Allendale). 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, 2018.

We expect to reinvest approximately $27.3 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2019, of which $11.2 million has been incurred through June 30, 2019. 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, 2018. We paid the remaining $10.4 million of the purchase price for two biomass plants in South Carolina when the transaction closed on July 31, 2019. We expect to pay the $20 million purchase price for the equity ownership interests in two biomass plants from AltaGas in the third quarter of 2019.

Other than this payment, we do not expect any other material or unusual requirements for cash outflows in 2019 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, 2019	Six months ended June 30, 2018	Change
Net cash provided by operating activities	$ 68.1	$ 78.4	$ (10.3)
Net cash provided by (used in) investing activities	1.1	(2.4)	3.5
Net cash used in financing activities	(66.8)	(78.2)	11.4

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, 2019, the net decrease in cash provided by operating activities of $10.3 million was primarily the result of the following:

- *Working capital* – changes in working capital resulted in a $24.5 million decrease in cash flows from operating activities from the comparable 2018 period. Cash flows from operations in the comparable 2018 period benefitted from a $17.7 million change in working capital at our Kapuskasing and North Bay projects (due to the expiration of enhanced dispatch agreements on December 31, 2017) and San Diego projects (which ceased operations in February 2018); and

- *Contract extension* – the extension of the energy purchase agreement 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 2018 period. These factors had a $4.9 million negative impact on cash flows provided by operating activities.

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

- *Major maintenance* – we performed a planned major maintenance outage at our Manchief project in the comparable 2018 period and had no such outage in the six months ended June 30, 2019, resulting in a $7.9 million positive impact on cash flows from operations ;

- *Hydrological conditions* – higher water flows at our Curtis Palmer project, partially offset by lower water flows at our Mamquam project, had a $7.5 million positive impact on cash flows provided by operating activities; and

- *Tunis operations* – the Tunis project commenced commercial operations in October 2018 and recorded revenue of $2.1 million in the six months ended June 30, 2019. Additionally, Tunis incurred $4.1 million of non-recurring maintenance expense in the comparable 2018 period to prepare the project for commercial operations.

Investing Activities

For the six months ended June 30, 2019, the net increase in cash provided by investing activities of $3.5 million was primarily the result of the following:

- *Proceeds from asset sales* – we received $1.5 million of cash proceeds from the sale of equipment at our San Diego projects;
- *Investment in unconsolidated affiliate* – we paid $1.1 million to acquire an additional 0.25% ownership of Koma in the comparative 2018 period; and
- *Capitalized plant additions* – capitalized plant additions were $0.9 million lower in the six months ended June 30, 2019 than the comparable 2018 period.

Financing Activities

For the six months ended June 30, 2019, the net decrease in cash used in financing activities of $11.4 million was primarily the result of the following:

- *Convertible debenture redemptions* – we paid $18.5 million to redeem and cancel the Series D Debentures in full during the six months ended June 30, 2019. In the comparable 2018 period, 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;
- *Corporate and project-level debt repayments* – we made $24.8 million less principal payments than the comparable 2018 period;
- *Common share repurchases* – we paid $0.8 million in the six months ended June 30, 2019 to repurchase and cancel common shares as compared to $9.2 million in the comparative 2018 period;
- *Deferred financing costs* – we incurred $4.8 million of deferred financing costs related to the issuance of the Series E Debentures in the comparable 2018 period; and
- *Dividends paid to preferred shareholders* – we paid $0.6 million of lower dividends to preferred shareholders than the comparable 2018 period.

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

- *Convertible debenture issuance* – we received $92.2 million from the issuance of the Series E Debentures in the comparable 2018 period;
- *Preferred share repurchases* – we paid $7.9 million in the six months ended June 30, 2019 to repurchase and cancel preferred shares as compared to $4.5 million in the comparative 2018 period; and
- *Vested LTIP* – we made $1.1 million of higher cash payments for withholding tax for vested LTIP than the comparable 2018 period.

Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2019:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2019	2020	2021	2022	2023	Thereafter
Senior secured term loan facility [(1)]	April 2023	4.14 % - 5.15 %	$ 417.5	$ 32.5	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ —
MTNs	June 2036	5.95 %	160.5	—	—	—	—	—	160.5
Convertible Debenture	January 2025	6.00 %	87.9	—	—	—	—	—	87.9
Total Corporate Debt			$ 665.9	$ 32.5	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ 248.4

(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 June 30, 2019. 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 July 31, 2019, 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 June 30, 2019. 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	2019	2020	2021	2022	2023	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.26 % - 6.38 %	$ 19.5	$ 1.6	$ 3.1	$ 2.7	$ 3.3	$ 3.3	$ 5.5
Total Consolidated Projects			19.5	1.6	3.1	2.7	3.3	3.3	5.5
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			$ 62.4	$ 6.8	$ 10.9	$ 11.5	$ 13.4	$ 14.3	$ 5.5

(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, and our preferred shares (to the extent we choose to pursue any such repurchases); collateral and investment in our projects through capital expenditures, including major maintenance and business development costs; and dividend payments to preferred shareholders of a subsidiary company. We expect to pay the $20 million purchase price for the equity ownership interests in two biomass plants from AltaGas in the third quarter of 2019.

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 and maintenance 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 $1.2 million in 2019 (of which $0.4 million was reinvested in the six months ended June 30, 2019) in our portfolio, including equity method investments, in the form of project capital expenditures, and incur $26.2 million of maintenance expenses (of which $10.8 million was incurred in the six months ended June 30, 2019). 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, 2018. We do not expect any other material or unusual requirements for cash outflows for 2019 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 2019 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

Recently Adopted and Recently Issued Accounting Guidance

See Note 1 to the consolidated financial statements in this Quarterly Report on Form 10-Q.

Off-Balance Sheet Arrangements

As of June 30, 2019, 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, 2018.

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.