ATLANTIC POWER CORP
Form 10-Q
November 01, 2018
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10 Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2018
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

COMMISSION FILE NUMBER 001 34691

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada	55 0886410
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
3 Allied Drive, Suite 155	
Dedham, MA	02026
(Address of principal executive offices)	(Zip code)

(617) 977 2400

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b 2 of the Exchange Act. (Check one):

Large accelerated filer Accelerated filer Non accelerated filer Smaller reporting company
Emerging growth company

If an emerging company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b 2 of the Exchange Act). Yes No

The number of shares outstanding of the registrant's Common Stock as of October 31, 2018 was 109,994,268.

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ATLANTIC POWER CORPORATION

FORM 10 Q

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2018

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GENERAL

In this Quarterly Report on Form 10 Q, references to “Cdn$” and “Canadian dollars” are to the lawful currency of Canada and references to “$”, “US$” and “U.S. dollars” are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

Unless otherwise stated, or the context otherwise requires, references in this Quarterly Report on Form 10 Q to “we,” “us,” “our,” “Atlantic Power” and the “Company” refer to Atlantic Power Corporation, those entities owned or controlled by Atlantic Power Corporation and predecessors of Atlantic Power Corporation.

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ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

Assets	September 30, 2018 (unaudited)	December 31, 2017
Current assets:		
Cash and cash equivalents	$ 57.6	$ 78.7
Restricted cash	0.3	6.2
Accounts receivable	33.2	52.7
Current portion of derivative instruments asset (Notes 8 and 9)	6.4	2.7
Inventory	16.9	17.7
Prepayments	5.4	6.9
Income taxes receivable	0.7	1.0
Other current assets	3.4	3.1
Total current assets	123.9	169.0
Property, plant, and equipment, net	567.9	602.3
Equity investments in unconsolidated affiliates (Notes 2 and 5)	155.7	163.7
Power purchase agreements and intangible assets, net	179.2	191.2
Goodwill	21.3	21.3
Derivative instruments asset (Notes 8 and 9)	1.2	2.8
Other assets	9.4	8.5
Total assets	$ 1,058.6	$ 1,158.8
Liabilities		
Current liabilities:		
Accounts payable	$ 2.1	$ 2.2
Accrued interest	4.0	0.3
Other accrued liabilities	20.3	25.5
Current portion of long-term debt (Note 6)	78.1	99.5
Current portion of derivative instruments liability (Notes 8 and 9)	9.1	4.4
Other current liabilities	0.5	1.0
Total current liabilities	114.1	132.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 6)	557.9	616.3
Convertible debentures, net of discount and unamortized deferred financing costs (Note 7)	99.1	105.4
Derivative instruments liability (Notes 8 and 9)	16.9	19.9
Deferred income taxes	17.7	11.7
Power purchase and fuel supply agreement liabilities, net	22.3	24.1
Asset retirement obligations, net	47.1	45.3
Other long-term liabilities	5.7	6.4

Total liabilities	880.8	962.0
Equity		
Common shares, no par value, unlimited authorized shares; 110,281,935 and 115,211,976 issued and outstanding at September 30, 2018 and December 31, 2017	1,264.5	1,274.8
Accumulated other comprehensive loss (Note 4)	(139.5)	(134.8)
Retained deficit	(1,146.5)	(1,158.4)
Total Atlantic Power Corporation shareholders' equity	(21.5)	(18.4)
Preferred shares issued by a subsidiary company (Note 13)	199.3	215.2
Total equity	177.8	196.8
Total liabilities and equity	$ 1,058.6	$ 1,158.8

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Project revenue:				
Energy sales (Note 3)	$ 25.0	$ 36.5	$ 94.8	$ 113.6
Energy capacity revenue (Note 3)	29.5	37.9	72.9	85.7
Other (Note 3)	10.9	34.2	43.9	131.7
	65.4	108.6	211.6	331.0
Project expenses:				
Fuel	16.7	26.2	54.0	79.1
Operations and maintenance	18.0	19.8	66.5	63.4
Depreciation and amortization	21.0	31.4	65.7	90.5
	55.7	77.4	186.2	233.0
Project other income (loss):				
Change in fair value of derivative instruments (Notes 8 and 9)	—	(1.9)	3.6	(5.8)
Equity in earnings (loss) of unconsolidated affiliates (Notes 2 and 5)	10.2	9.2	33.7	(36.1)
Interest, net	(0.4)	(2.2)	(1.4)	(6.6)
Impairment	—	(57.3)	—	(57.3)
Other income, net (Note 2)	6.7	0.1	6.7	0.1
	16.5	(52.1)	42.6	(105.7)
Project income (loss)	26.2	(20.9)	68.0	(7.7)
Administrative and other expenses:				
Administration	5.7	5.5	17.9	17.6
Interest expense, net	14.6	13.8	40.7	49.5
Foreign exchange loss (gain)	4.5	9.4	(9.1)	17.7
Other expense, net (Note 9)	2.5	—	0.3	—
	27.3	28.7	49.8	84.8
(Loss) income from operations before income taxes	(1.1)	(49.6)	18.2	(92.5)
Income tax expense (benefit) (Note 10)	3.6	(15.9)	7.7	(38.5)
Net (loss) income	(4.7)	(33.7)	10.5	(54.0)
Net (loss) income attributable to preferred shares of a subsidiary company (Note 13)	(1.5)	(0.8)	(1.6)	3.5

Net (loss) income attributable to Atlantic Power Corporation	$ (3.2)	$ (32.9)	$ 12.1	$ (57.5)
Net (loss) income per share attributable to Atlantic Power Corporation shareholders: (Note 12)				
Basic	$ (0.03)	$ (0.29)	$ 0.11	$ (0.50)
Diluted	(0.03)	(0.29)	0.11	(0.50)
Weighted average number of common shares outstanding: (Note 12)				
Basic	111.1	115.3	112.8	115.1
Diluted	111.1	115.3	140.1	115.1

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of U.S. dollars)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net (loss) income	$ (4.7)	$ (33.7)	$ 10.5	$ (54.0)
Other comprehensive income (loss), net of tax:				
Unrealized gain (loss) on hedging activities	$ 0.1	$ —	$ 0.3	$ (0.3)
Net amount reclassified to earnings	0.1	0.1	0.3	0.5
Net unrealized gain on derivatives	0.2	0.1	0.6	0.2
Defined benefit plan, net of tax	—	—	—	0.1
Foreign currency translation adjustments	2.2	9.2	(5.3)	15.9
Other comprehensive income (loss), net of tax	2.4	9.3	(4.7)	16.2
Comprehensive (loss) income	(2.3)	(24.4)	5.8	(37.8)
Less: Comprehensive (loss) income attributable to preferred shares of a subsidiary company	(1.5)	(0.8)	(1.6)	3.5
Comprehensive (loss) income attributable to Atlantic Power Corporation	$ (0.8)	$ (23.6)	$ 7.4	$ (41.3)

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

(Unaudited)

	Nine months ended September 30,	
	2018	2017
Cash provided by operating activities:		
Net income (loss)	$ 10.5	$ (54.0)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	65.7	90.5
Loss on disposal of fixed assets	—	0.1
Gain on fair value adjustment to equity investment resulting from step acquisition	(6.7)	—
Share-based compensation	1.8	1.6
Long-lived asset and goodwill impairment	—	57.3
Equity in (earnings) loss from unconsolidated affiliates	(33.7)	36.1
Distributions from unconsolidated affiliates	37.4	30.9
Unrealized foreign exchange (gain) loss	(8.6)	17.0
Change in fair value of derivative instruments	(3.5)	5.8
Change in fair value of convertible debenture conversion option derivative	0.2	—
Amortization of debt discount and deferred financing costs	7.4	7.8
Change in deferred income taxes	5.0	(42.1)
Change in other operating balances		
Accounts receivable	19.7	(11.5)
Inventory	0.8	(4.2)
Prepayments and other assets	3.2	0.6
Accounts payable	(1.0)	0.3
Accruals and other liabilities	(0.4)	2.5
Cash provided by operating activities	97.8	138.7
Cash used in investing activities:		
Cash paid for acquisition, net of cash received	(12.8)	—
Deposit for acquisition	(2.6)	—
Purchase of property, plant and equipment	(1.5)	(5.7)
Cash used in investing activities	(16.9)	(5.7)
Cash used in financing activities:		
Proceeds from convertible debenture issuance	92.2	—
Repayment of convertible debentures	(88.1)	(0.1)

Common share repurchases	(12.3)	(0.2)
Preferred share repurchases	(8.0)	(3.1)
Repayment of corporate and project-level debt	(79.5)	(86.3)
Cash payments for vested LTIP units withheld for taxes	(0.8)	(0.8)
Deferred financing costs	(5.1)	—
Dividends paid to preferred shareholders	(6.3)	(6.5)
Cash used in financing activities:	(107.9)	(97.0)
Net (decrease) increase in cash, restricted cash and cash equivalents	(27.0)	36.0
Cash, restricted cash and cash equivalents at beginning of period	84.9	98.9
Cash, restricted cash and cash equivalents at end of period	$ 57.9	$ 134.9
Supplemental cash flow information		
Interest paid	$ 30.3	$ 44.2
Income taxes paid, net	$ 2.5	$ 3.4
Accruals for construction in progress	$ —	$ —

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

1. Nature of business

General

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 September 30, 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. At September 30, 2018, three of our Ontario projects were not in operation, two because of contract expirations on December 31, 2017, and the other, Tunis, has a forward-starting 15-year contractual agreement that commenced with commercial operation of the plant in October of 2018. In early February 2018, our three plants in San Diego, totaling 112 MW on a gross and net ownership basis, ceased operations. The sixteen projects in operation at September 30, 2018 have generating capacity of approximately 1,561 MW on a gross ownership basis and approximately 1,215 MW on a net ownership basis.

Atlantic Power is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange (“TSX”) under the symbol “ATP” and on the New York Stock Exchange (“NYSE”) under the symbol “AT.” Our registered office is located at 215-10451 Shellbridge Way, Richmond, British Columbia V6X 2W8 Canada and our headquarters is located at 3 Allied Drive, Suite 155, Dedham, Massachusetts 02026, USA. Our telephone number in Dedham is (617) 977 2400 and the address of our website is www.atlanticpower.com. Information contained on Atlantic Power’s website or that can be accessed through its website is not incorporated into and does not constitute a part of this Quarterly Report on Form 10 Q. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website. We make available on our website, free of charge, our Annual Report on Form 10 K, Quarterly Reports on Form 10 Q, Current Reports on Form 8 K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission (“SEC”). Additionally, we make available on our website our Canadian securities filings, which are not incorporated by reference into our Exchange Act filings.

Basis of presentation

The interim condensed consolidated financial statements included in this Quarterly Report on Form 10 Q have been prepared in accordance with the SEC regulations for interim financial information and with the instructions to Form 10 Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10 K for the year ended December 31, 2017. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim condensed consolidated financial statements present fairly our consolidated financial position as of September 30, 2018, the results of operations and comprehensive income (loss) for the three and nine months ended September 30, 2018 and 2017, and our cash flows for the nine months ended September 30, 2018 and 2017 in accordance with U.S. generally accepted accounting policies. In the opinion of management, all adjustments (consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair value of assets acquired and liabilities assumed in purchase accounting, the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations and equity-based compensation. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates" in our Annual Report on Form 10-K for the year ended December 31, 2017. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Recently issued accounting standards

Adopted

In May 2017, the Financial Accounting Standards Board ("FASB") issued authoritative guidance to address diversity in practice and cost and complexity of applying the guidance relating to stock compensation when there is a change to the terms or conditions of a share-based payment award. The guidance is effective for fiscal years beginning after

December 15, 2017, with early adoption permitted. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In November 2016, the FASB issued authoritative guidance to address diversity in practice of presenting changes in restricted cash on the statement of cash flows. The new guidance requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. We adopted this guidance on January 1, 2018 and it was applied retrospectively to cash flows used in investing activities on the consolidated statements of cash flows for the nine months ended September 30, 2017. As a result of adoption, cash flows used in investing activities were retrospectively decreased by $0.8 million for the nine months ended September 30, 2017.

In October 2016, the FASB issued authoritative guidance, which amends existing guidance related to the recognition of current and deferred income taxes for intra-entity asset transfers. Under the new guidance, current and deferred income tax consequences of an intra-entity asset transfer, other than an intra-entity asset transfer of inventory, are now recognized when the transfer occurs. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In August 2016, the FASB issued authoritative guidance intended to clarify classification of specific cash flows that have aspects of more than one class of cash flows. As a result of this new guidance, entities should be applying specific GAAP in the following eight cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity recognizes revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements. Accordingly, we did not record a transition adjustment. The standard also requires new disclosures that include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. These disclosures can be found in Note 3, Revenue from contracts.

Issued

In February 2016, the FASB issued authoritative guidance intended to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a right-of-use asset and a lease liability, measured on a discounted basis, at the commencement date for all leases with terms greater than twelve months. Additionally, this guidance will require disclosures to help investors and other financial statement users to better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements. Any leases that expire before the initial application date will not require any accounting adjustment. This guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We expect to elect certain practical expedients permitted, including the expedient that permits us to retain our existing lease assessment and classification. In July 2018, the FASB issued further authoritative guidance to provide an additional transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustments to the opening balance of retained earnings in the period of adoption. We will elect this transition method. We are currently finalizing our adoption process, which includes the evaluation of lease contracts compared to the new standard. While we are currently completing our evaluation of the impact the new guidance will have on our financial position and results of operations, we expect to recognize lease liabilities and right of use assets. The extent of the increase to assets and liabilities associated with these amounts remains to be finalized. However, we expect the impact to be material.

In August 2017, the FASB issued authoritative guidance to align an entity’s risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The guidance expands and refines hedge accounting for both nonfinancial and financial risk components and aligns the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The guidance is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. We do not expect this to have a material impact to the consolidated financial statements upon adoption.

In February 2018, the FASB issued authoritative guidance to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The guidance is effective for fiscal years beginning after December 15, 2018. We do not expect this to have a material impact to the consolidated financial statements upon adoption.

In August 2018, the FASB issued authoritative guidance to modify the disclosure requirements on fair value measurement disclosures. The guidance requires removals of certain disclosures, such as the amount of and reasons for transfers between level 1 and level 2 of fair value hierarchy and the policy for timing of transfers between levels. The guidance further requires modifications and additions surrounding the disclosures of level 3 fair value measurements and related unrealized gains and losses. The guidance is effective for fiscal years beginning after December 15, 2019. We do not expect this to have a material impact to the consolidated financial statements upon adoption.

In August 2018, the FASB issued authoritative guidance to remove disclosures that no longer are considered cost-beneficial, clarify the specific requirements of disclosures, and add disclosure requirements identified as relevant. The scope of the guidance is broad and includes reporting comprehensive income, debt modifications and extinguishments and other sub topics. The guidance is effective for fiscal years beginning after December 15, 2019. We are currently evaluating the impact that adoption will have on our disclosures.

2. Acquisitions

Koma Kulshan Associates

On June 18, 2018, we purchased a 0.5% general partner interest in Concrete Hydro Partners L.P. ("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 Kulshan Associates, L.P. ("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 the 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") for a total purchase price of $12.5 million including working capital. As a result of this purchase, we own 100% of Koma and consolidated the project on the date of the acquisition. We completed this acquisition because we view hydro projects as assets that will provide us both near and long-term value.

Our acquisition of Koma is accounted for under the acquisition method of accounting as of the transaction closing date. 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. The preliminary purchase price allocation for the business combination is estimated as follows:

Fair value of consideration transferred:		
Cash	$	12.5
Other items to be allocated to identifiable assets acquired and liabilities assumed:		
Book value of our investment in Koma at the acquisition date		5.4
Gain recognized from step acquisition		6.7
Total purchase price	$	24.6
Preliminary purchase price allocation		
Cash	$	0.8
Working capital		0.1
Property, plant, and equipment		1.2
Intangible assets		24.8
Deferred tax liability		(0.5)
Asset retirement obligation		(1.8)
Total identifiable net assets	$	24.6

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The fair values of the assets acquired and liabilities assumed, as well as the fair value of our previous 50% equity interest in Koma, were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of the acquired facility, remaining useful life and a discount rate based on the weighted average cost of capital adjusted for the risk and characteristics of the project. We recognized a $6.7 million gain recorded in other income 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. The $24.8 million of intangible assets recorded will be amortized straight-line through the remaining life of Koma's PPA, which expires on March 31, 2037.

Koma contributed $0.3 million of revenue and a loss of less than $0.1 million to the consolidated statements of operations for the period from July 27, 2018 to September 30, 2018. The impact to pro forma results of operations was not significant to the three and nine months ended September 30, 2018 and 2017.

South Carolina Biomass Plants

On September 20, 2018, we executed an agreement to acquire two biomass plants in South Carolina from EDF Renewables Inc. ("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 and is recorded as a component of long-term other assets on the consolidated balance sheets at September 30, 2018. The remainder of the purchase price will be paid at closing.

3. Revenue from contracts

Accounting policy

We recognize energy sales revenue on a gross basis when electricity and steam are delivered and capacity revenue when capacity is provided under the terms of the related contracts. PPAs, steam purchase arrangements and energy services agreements are long term contracts with performance obligations to provide electricity, steam and capacity on a predetermined basis.

For certain PPAs determined to be operating leases, we recognize lease income consistent with the recognition of energy sales and capacity revenue. When energy is delivered and capacity is provided, we recognize lease income as a component of energy sales and capacity revenue.

Nature of goods and services

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, which have expiration dates ranging from June 30, 2019 to March 31, 2037, 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). 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

The following is a description of principal activities from which we generate our revenue.

Products and services	Nature, timing of satisfaction of performance obligations, and significant payment terms
Energy	Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations. The price of energy could be contracted under PPAs at set prices or merchant sales based on market merchant price. Energy revenue is billed and paid on a monthly basis.
Energy capacity	Capacity revenues are recognized when contractually earned, and consist of revenues billed to a third party at a negotiated contract price under the applicable PPAs for making installed generation capacity available in order to satisfy reliability requirements or merchant capacity sales based on the market price for such capacity. Energy capacity is billed and paid on a monthly basis.
Other revenue includes	the following:
Steam energy and capacity	Steam revenue is recognized upon delivery to the customer. Steam capacity payments under the applicable PPAs are recognized as the amount billable under the respective PPA. Steam capacity is billed and paid on a monthly basis.
Waste heat	We generate electricity from excess steam provided by a nearby pipeline and its pumping station in the Canada segment. Waste heat is earned when it is generated and paid as a portion of monthly energy and capacity billing.
Enhanced dispatch contracts	We also bill and are paid for curtailment of energy generation under certain contractual arrangements with our offtaker. This revenue is recognized monthly under the terms of those agreements.
Ancillary and transmission services	We provide ancillary and transmission services to our customers under the terms of our PPAs. These services are billed and paid on a monthly basis.
Asset management and operation, operation and maintenance	We provide asset management and operation supervision to the Frederickson project, a facility that we jointly own with Puget Sound Energy. We also provide operation and maintenance services to several electric energy customers under the PPAs. All services are billed and paid

on a monthly basis.

Disaggregation of revenue

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. Each segment contains various power generation projects and performance obligations as described above. For more detailed information about reportable segments, see Note 14, Segment and geographical information. Revenue, receivables and contract liabilities by segment consists of following:

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	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
Steam energy and capacity revenue	2.7	—	—	—	2.7
Waste heat revenue	—	—	—	—	—
Enhanced dispatch contracts	—	—	6.1	—	6.1
Ancillary and transmission services	1.0	—	0.6	—	1.6
Asset management and operation	—	—	—	0.2	0.2
Miscellaneous revenue	—	0.3	—	—	0.3
	36.3	13.8	15.1	0.2	65.4

	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
Steam energy and capacity revenue	2.4	7.7	—	—	10.1
Waste heat revenue	—	—	0.2	—	0.2
Enhanced dispatch contracts	—	—	17.8	—	17.8
Ancillary and transmission services	1.0	—	4.9	—	5.9
	—	—	—	0.2	0.2

Asset management and operation	39.8	35.1	33.5	0.2	108.6

	Nine Months Ended September 30, 2018				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 62.9	$ 10.1	$ 21.8	$ —	$ 94.8
Energy capacity revenue	41.5	22.9	8.5	—	72.9
Steam energy and capacity revenue	8.9	2.8	—	—	11.7
Waste heat revenue	—	—	0.1	—	0.1
Enhanced dispatch contracts	—	—	21.1	—	21.1
Ancillary and transmission services	3.6	—	6.8	—	10.4
Asset management and operation	—	—	—	0.7	0.7
Miscellaneous revenue	—	(0.1)	—	—	(0.1)
	116.9	35.7	58.3	0.7	211.6

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	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	39.0	8.0	—	85.8
Steam energy and capacity revenue	8.4	23.3	—	—	31.7
Waste heat revenue	—	—	0.5	—	0.5
Enhanced dispatch contracts	—	—	82.8	—	82.8
Ancillary and transmission services	2.8	—	13.8	—	16.6
Asset management and operation	—	—	—	0.7	0.7
Miscellaneous revenue	—	(0.7)	—	—	(0.7)
	116.3	86.2	127.8	0.7	331.0

Contract balances

The following table provides information about receivables, contract assets and contract liabilities from contracts with customers.

	September 30, 2018	December 31, 2017
Accounts receivables	$ 33.2	$ 52.7

Contract assets	—	—
Contract liabilities	0.5	1.0

Contract liabilities as of September 30, 2018 include a $0.4 million water license fee at Mamquam, which is a pass-through cost. Contract liabilities as of December 31, 2017 include recoverable wood fuel costs under the PPA and property tax at Williams Lake, which is proportionally estimated, pending receipt of an actual tax bill. The total $1.0 million was recognized as revenues from ancillary and transmission services in the first quarter of 2018.

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4. Changes in accumulated other comprehensive loss by component

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Foreign currency translation				
Balance at beginning of period	$ (141.8)	$ (141.6)	$ (134.3)	$ (148.3)
Other comprehensive loss:				
Foreign currency translation adjustments(1)	2.2	9.2	(5.3)	15.9
Balance at end of period	$ (139.6)	$ (132.4)	$ (139.6)	$ (132.4)
Pension				
Balance at beginning of period	$ (1.6)	$ (0.8)	$ (1.6)	$ (0.9)
Other comprehensive loss:				
Curtailment gain	—	—	—	0.1
Tax expense	—	—	—	—
Total Other comprehensive income before reclassifications, net of tax	—	—	—	0.1
Total amount reclassified from accumulated other comprehensive income, net of tax	—	—	—	—
Total other comprehensive income	—	—	—	0.1
Balance at end of period	$ (1.6)	$ (0.8)	$ (1.6)	$ (0.8)
Cash flow hedges				
Balance at beginning of period	$ 1.5	$ 0.8	$ 1.1	$ 0.7
Other comprehensive income (loss):				
Net change from periodic revaluations	0.1	(0.1)	0.4	(0.6)
Tax benefit (expense)	—	0.1	(0.1)	0.3

Total Other comprehensive (loss) income before reclassifications, net of tax	0.1	—	0.3	(0.3)
Net amount reclassified to earnings:				
Interest rate swaps(2)	0.1	0.2	0.4	0.9
Tax expense	—	(0.1)	(0.1)	(0.4)
Total amount reclassified from accumulated other comprehensive loss, net of tax	0.1	0.1	0.3	0.5
Total other comprehensive income	0.2	0.1	0.6	0.2
Balance at end of period	$ 1.7	$ 0.9	$ 1.7	$ 0.9

(1) In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in interest expense, net on the accompanying consolidated statements of operations.

(3)

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5. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three and nine months ended September 30, 2018 and 2017, respectively, for our proportional ownership interest in equity method investments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating results	2018	2017	2018	2017
Revenue				
Frederickson	$ 5.9	$ 5.9	$ 15.7	$ 16.0
Orlando Cogen, LP	15.1	14.3	44.7	40.4
Koma Kulshan Associates (1)	—	0.3	1.2	1.4
Chambers Cogen, LP	10.6	10.5	33.4	33.1
Selkirk Cogen Partners, LP (2)	—	—	—	1.8
	31.6	31.0	95.0	92.7
Project expenses				
Frederickson	4.0	4.9	10.7	16.8
Orlando Cogen, LP	7.3	7.2	21.9	22.1
Koma Kulshan Associates (1)	—	0.3	0.6	0.8
Chambers Cogen, LP	9.7	8.9	26.9	27.2
Selkirk Cogen Partners, LP (2)	—	—	—	2.8
	21.0	21.3	60.1	69.7
Project other expense				
Frederickson	—	—	—	—
Orlando Cogen, LP	—	—	—	—
Koma Kulshan Associates (1)	—	—	—	—
Chambers Cogen, LP	(0.4)	(0.5)	(1.2)	(48.5)
Selkirk Cogen Partners, LP (2)	—	—	—	(10.6)

	(0.4)	(0.5)	(1.2)	(59.1)
Project income (loss)				
Frederickson	1.9	1.0	5.0	(0.8)
Orlando Cogen, LP	7.8	7.1	22.8	18.3
Koma Kulshan Associates (1)	—	—	0.6	0.6
Chambers Cogen, LP	0.5	1.1	5.3	(42.6)
Selkirk Cogen Partners, LP (2)	—	—	—	(11.6)
Equity in earnings (loss) of unconsolidated affiliates	$ 10.2	$ 9.2	$ 33.7	$ (36.1)
Distributions from equity method investments	(10.1)	(13.7)	(37.4)	(30.9)
Surplus (deficit) of earnings of equity method investments, net of distributions	$ 0.1	$ (4.5)	$ (3.7)	$ (67.0)

(1) On July 27, 2018, we purchased the remaining 50% of Koma and consolidated the project.

(2) In November 2017, we sold our 17.7% interest in Selkirk.

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6. Long term debt

Long term debt consists of the following:

	September 30, 2018	December 31, 2017	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2023(1)	$ 470.0	$ 540.0	LIBOR(2) plus 3.00 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	162.3	167.4	5.95 %
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019 (3)	—	7.2	LIBOR plus 3.125 %
Cadillac term loan, due 2025 (4)	21.8	24.0	LIBOR plus 1.49 %
Other long-term debt	—	0.1	5.50 % - 6.70 %
Less: unamortized discount	(9.9)	(12.8)	
Less: unamortized deferred financing costs	(8.2)	(10.1)	
Less: current maturities	(78.1)	(99.5)	
Total long-term debt	$ 557.9	$ 616.3	

Current maturities consist of the following:

	September 30, 2018	December 31, 2017	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2023(1)	$ 75.0	$ 90.0	LIBOR(2) plus 3.00 %

Epsilon Power Partners term facility, due 2019 (3)		—		6.5	LIBOR	plus 3.125 %
Cadillac term loan, due 2025 (4)		3.1		3.0	LIBOR	plus 1.49 %
Total current maturities	$	78.1	$	99.5		

(1) On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the term loan credit agreement. The portion of the senior secured term loan facility classified as current is based on principal payments required to reduce the aggregate principal amount of senior secured term loan outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule.

(2) London Interbank Offered Rate ("LIBOR") cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $442.2 million of the $470 million outstanding aggregate borrowings under our senior secured term loan facility at September 30, 2018. See Note 9, Accounting for derivative instruments and hedging activities for further details. On October 31, 2018, the repricing of the senior secured term loan facility became effective, reducing the interest rate to LIBOR plus 2.75% with no change to the 1.00% LIBOR floor.

(3) In June 2018, we pre-paid the remaining $5.6 million principal amount originally due in 2018 and 2019.

(4) We have entered into interest rate swap agreements to economically fix our exposure to changes in interest rates for this non-recourse debt. See Note 9, Accounting for derivative instruments and hedging activities, for further details.

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7. Convertible debentures

Convertible debentures consist of the following:

	September 30, 2018	December 31, 2017
6.00% Debentures due January 2025 (Series E) (Cdn $115.0 million)	$ 88.8	$ —
5.75% Debentures due June 2019 (Series C)	—	42.5
6.00% Debentures due December 2019 (Series D) (Cdn $24.7 million)	19.1	64.5
Less: Unamortized deferred financing costs	(4.5)	(1.6)
Less: Unamortized discount	(4.3)	—
Total convertible debentures	$ 99.1	$ 105.4

On January 29, 2018, we closed the sale of our offering (the “Series E Debenture Offering”) of Cdn$100 million aggregate principal amount of 6.00% Series E convertible unsecured subordinated debentures (the “Series E Debentures”). We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debenture Offering to cover over-allotments. The underwriters exercised that option for the full Cdn$15 million aggregate principal amount on February 2, 2018.

On the initial closing date, we received net proceeds from the Series E Debentures Offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On January 29, 2018, we issued a notice to redeem all of the $42.5 million remaining principal amount of 5.75% Series C convertible unsecured subordinated debentures due June 2019 (the “Series C Debentures”) with the use of a portion of the proceeds from the Series E Debenture Offering.

On February 2, 2018, we issued a notice to redeem Cdn$56.2 million principal amount of the 6.00% Series D extendible convertible unsecured subordinated debentures due December 2019 (the “Series D Debentures”) with the remaining proceeds from the Series E Debentures Offering. After the partial redemption, Cdn$24.7 million ($19.1 million) aggregate principal amount of the Series D Debentures remains outstanding.

The Series E Debentures have a maturity date of January 31, 2025. The Series E Debentures bear interest at a rate of 6.00% per year, and are convertible into our common shares at an initial conversion rate of approximately 238.0952 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$4.20 per common share.

We assessed the conversion option of the Series E Debentures and determined it should be separated from the host instrument and accounted for as an embedded derivative liability as the conversion option is in a currency different from our functional currency. Changes in the fair value of the conversion option derivative are recorded in the consolidated statements of operation. The conversion option derivative was initially measured at fair value ($4.7 million), with the host contract carried at a value equal to the difference between the carrying value of the Series E Debenture and the fair value of the derivative. Accordingly, no gain or loss was recorded on the initial measurement of the derivative. The fair value of the conversion option derivative was $4.9 million as of September 30, 2018. The portion of the proceeds allocated to the separated derivative also created a discount of $4.7 million, which will be amortized to interest expense over the maturity period of the Series E Debentures. For additional information, see Note 9, Accounting for derivative instruments and hedging activities.

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8. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of September 30, 2018 and December 31, 2017. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	September 30, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 57.6	$ —	$ —	$ 57.6
Restricted cash	0.3	—	—	0.3
Derivative instruments asset	—	7.6	—	7.6
Total	$ 57.9	$ 7.6	$ —	$ 65.5
Liabilities:				
Derivative instruments liability	$ —	$ 21.1	$ 4.9	$ 26.0
Total	$ —	$ 21.1	$ 4.9	$ 26.0

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 78.7	$ —	$ —	$ 78.7
Restricted cash	6.2	—	—	6.2
Derivative instruments asset	—	5.5	—	5.5
Total	$ 84.9	$ 5.5	$ —	$ 90.4
Liabilities:				
Derivative instruments liability	$ —	$ 24.3	$ —	$ 24.3

Total	$ —	$ 24.3	$ —	$ 24.3

The fair values of our interest rate swaps, foreign exchange forward contracts, natural gas swaps and gas purchase agreements are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk-free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of September 30, 2018, the credit valuation adjustments resulted in a $1.4 million net increase in fair value, which consists of a $0.1 million pre tax gain in other comprehensive income and a $1.3 million gain in change in fair value of derivative instruments. As of December 31, 2017, the credit valuation adjustments resulted in a $2.2 million net increase in fair value, which consists of a $0.2 million pre tax gain in other comprehensive income and a $2.0 million gain in change in fair value of derivative instruments.

The conversion option derivative for the Series E Debentures is classified within Level 3 of the fair value hierarchy. The significant unobservable inputs used in developing fair value include the volatility of our common shares and the fair value of the host contract, which is derived from recent similar convertible debenture offerings from peer companies. A discounted cash flow valuation technique is utilized to calculate to fair value of the conversion option derivative.

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The following table reconciles, for the three and nine months ended September 30, 2018, the beginning and ending balances for the conversion option derivative that is recognized at fair value in the consolidated financial statements, using significant unobservable inputs:

	Fair value Measurement Using Significant Unobservable Inputs (Level 3)	
	Three months ended September 30, 2018	Nine months ended September 30, 2018
Beginning balance	$ 2.3	$ 4.7
Total unrealized loss	2.6	0.2
Ending balance as of September 30, 2018	$ 4.9	$ 4.9

For cash and cash equivalents, accounts and other receivables, accounts payable and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

9. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value in each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase and sale agreements

We have a gas purchase agreement at our Nipigon project that expires on December 31, 2022 under which we purchase a minimum of 6,500 Gigajoules (“Gj”) of natural gas per day at a price of Cdn$4.57 per Gj. We also entered into a gas sales agreement for our Nipigon project under which we sell 6,500 Gj of natural gas per day at a price of Cdn$2.75 that expired on October 31, 2018. These agreements do not qualify for the normal purchase normal sales (“NPNS”) exemption and are accounted for as derivative financial instruments because we could not conclude that it is probable that these contracts will not settle net and will result in physical delivery. These derivative financial instruments are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have also entered into various natural gas sales and purchase agreements for approximately 700,000 Mmbtu to effectively mitigate seasonal fluctuation of future natural gas price at Morris from September through February 2019. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at September 30, 2018. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Natural gas swaps

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

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We have entered into various natural gas swaps to effectively fix the price of 13.2 million Mmbtu of future natural gas purchases at our Orlando project, which is approximately 90% of the remaining expected natural gas purchases at the project in 2018 and 100% of our share of the expected natural gas purchases in 2019 through 2021. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at September 30, 2018. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

Atlantic Power Limited Partnership Holdings (“APLP Holdings”) has entered into several interest rate swap agreements to mitigate its exposure to changes in interest at the Adjusted Eurodollar Rate. At September 30, 2018, these agreements totaled $442.2 million notional amount of the remaining $470.0 million aggregate principal amount of borrowings under the senior secured term loan facility (“Term Loan Facility”). These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the $700.0 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.00%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 4.00% all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 1.34%, resulting in an all-in rate of approximately 4.34% for $442.2 million of the Term Loan Facility. In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning September 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.1% through February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac’s debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive income (loss).

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our Medium Term Notes due June 23, 2036 (“MTNs”). Principal and interest payments for our senior secured term loans as well as our U.S. dollar-denominated convertible debentures are made in U.S. dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements.

In July 2017, we entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of 1.2481 in three tranches of Cdn$3.3 million each. One tranche of Cdn$3.3 million remains and will settle in December 2018. In July 2017, we also entered into foreign exchange forward contracts to sell a total of Cdn$10 million at an exchange rate of 1.2943. One tranche of Cdn$2.0 million remains and will settle in December 2018.

Foreign currency forward contracts are not designated as hedges, and changes in their market value are recorded in foreign exchange on the consolidated statements of operations at September 30, 2018.

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Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for NPNS exemption at September 30, 2018 and December 31, 2017:

	Units	September 30, 2018	December 31, 2017
Natural gas swaps	Natural Gas (Mmbtu)	13.2	9.9
Gas purchase agreements	Natural Gas (Gigajoules)	9.5	9.9
Interest rate swaps	Interest (US$)	636.7	412.6
Foreign currency forward contracts	Dollars (Cdn$)	5.3	25.0

Fair value of derivative instruments

We disclose derivative instrument assets and liabilities on a trade by trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

	September 30, 2018	
	Derivative Assets	Derivative Liabilities

Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.4
Interest rate swaps long-term	—	0.8
Total derivative instruments designated as cash flow hedges	—	1.2
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	6.3	—
Interest rate swaps long-term	1.2	—
Natural gas swaps current	—	0.2
Natural gas swaps long-term	—	1.5
Gas purchase agreements current	—	3.6
Gas purchase agreements long-term	—	14.6
Convertible debenture conversion option	—	4.9
Foreign currency forward contracts current	0.1	—
Total derivative instruments not designated as cash flow hedges	7.6	24.8
Total derivative instruments	$ 7.6	$ 26.0

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	December 31, 2017	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.6
Interest rate swaps long-term	—	1.5
Total derivative instruments designated as cash flow hedges	—	2.1
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	2.7	—
Interest rate swaps long-term	2.8	—
Natural gas swaps current	—	0.8
Natural gas swaps long-term	—	0.2
Gas purchase agreements current	—	2.9
Gas purchase agreements long-term	—	18.2
Foreign currency forward contracts current	—	0.1
Total derivative instruments not designated as cash flow hedges	5.5	22.2
Total derivative instruments	$ 5.5	$ 24.3

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Accumulated other comprehensive income

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

Three Months Ended September 30, 2018	Interest Rate Swaps
Accumulated OCI balance at June 30, 2018	$ 1.5
Change in fair value of cash flow hedges	0.1
Realized from OCI during the period	0.1
Accumulated OCI balance at September 30, 2018	$ 1.7

Three Months Ended September 30, 2017	Interest Rate Swaps
Accumulated OCI balance at June 30, 2017	$ 0.8
Change in fair value of cash flow hedges	—
Realized from OCI during the period	0.1
Accumulated OCI balance at September 30, 2017	$ 0.9

Nine Months Ended September 30, 2018	Interest Rate Swaps
Accumulated OCI balance at January 1, 2018	$ 1.1
Change in fair value of cash flow hedges	0.3
Realized from OCI during the period	0.3
Accumulated OCI balance at September 30, 2018	$ 1.7

Nine Months Ended September 30, 2017	Interest Rate Swaps
Accumulated OCI balance at January 1, 2017	$ 0.7
Change in fair value of cash flow hedges	(0.3)
Realized from OCI during the period	0.5
Accumulated OCI balance at September 30, 2017	$ 0.9

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

	Classification of loss (gain) recognized in income	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Gas purchase agreements	Fuel	$ 0.8	$ 3.1	2.5	$ 7.9
Natural gas swaps	Fuel	0.1	(0.7)	0.9	(1.2)
Interest rate swaps	Interest, net	(0.6)	0.9	(1.7)	2.6

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

	Classification of (loss) gain recognized in income	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Natural gas swaps	Change in fair value of derivatives	$ (0.2)	$ 0.2	$ (0.7)	$ (0.3)
Gas purchase agreements	Change in fair value of derivatives	0.5	(1.3)	2.1	(4.3)
Interest rate swaps	Change in fair value of derivatives	(0.3)	(0.8)	2.2	(1.2)
		$ —	$ (1.9)	3.6	(5.8)
Convertible debenture conversion option	Other expense, net	(2.6)	—	(0.2)	—
Foreign currency forwards	Foreign exchange (loss) gain	$ (0.4)	$ (0.2)	$ 0.2	$ (0.7)
X					

10. Income taxes

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

	2018	2017	2018	2017
Current income tax expense	$ 0.6	$ 1.3	$ 2.8	$ 3.6
Deferred income tax expense (benefit)	3.0	(17.2)	4.9	(42.1)
Total income tax expense (benefit), net	$ 3.6	$ (15.9)	$ 7.7	$ (38.5)

For the three and nine months ended September 30, 2018 and 2017

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 the Company's 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.

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.

As of September 30, 2018, we have recorded a valuation allowance of $155.9 million. The amount is comprised primarily of provisions against Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the U.S. and in Canada and available tax planning strategies.

11. Equity compensation plans

Long term incentive plan (“LTIP”)

The following table summarizes the changes in outstanding LTIP notional units during the nine months ended September 30, 2018:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2017	2,884,574	2.22
Granted	2,483,237	2.02
Vested and redeemed	(1,216,252)	2.24
Outstanding at September 30, 2018	4,151,559	$ 2.09

Cash payments made for vested notional units for the nine months ended September 30, 2018 and 2017 were $0.8 million and $0.7 million, respectively. Compensation expense for LTIP and Transition Equity Participation Agreement notional shares was $1.1 million and $2.6 million for the three and nine months ended September 30, 2018, respectively, and $0.9 million and $2.6 million for the three and nine months ended September 30, 2017, respectively.

Transition Equity Participation Agreement

We also have 539,904 transition notional shares outstanding at September 30, 2018 under the Transition Equity Participation Agreement with James J. Moore, Jr. Fifty percent of the transition notional shares granted in January 2015 with respect to fiscal year 2015 will vest upon the four-year anniversary of the date of grant and the remaining portion will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (Cdn$3.18) by at least 50% (Cdn$4.77).

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12. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) attributable to Atlantic Power Corporation by the weighted average common shares outstanding during their respective periods. Shares issued and shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted earnings (loss) per share is computed in a manner consistent with that of basic earnings (loss) per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The dilutive effect of our convertible debentures is calculated using the "if-converted method." Under the if-converted method, the debentures are assumed to be converted at the beginning of the period, and the resulting common shares are included in the denominator of the diluted earnings (loss) per share calculation for the entire period being presented. Interest expense, net of any income tax effects, would be added back to the numerator for purposes of the if-converted calculation. The outstanding equity compensation for non-vested LTIP and Transition Equity Participation Agreement notional shares are not considered outstanding for purposes of computing basic earnings (loss) per share. However, these instruments are included in the denominator, when dilutive, for purposes of computing diluted earnings (loss) per share under the treasury stock method.

The following table sets forth the calculation of basic and diluted (loss) earnings per share for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Basic	2018	2017	2018	2017
Numerator:				
Net (loss) income attributable to Atlantic Power Corporation	$ (3.2)	$ (32.9)	$ 12.1	$ (57.5)
Denominator:				
Weighted average basic shares outstanding	111.1	115.3	112.8	115.1

Basic (loss) earnings per share attributable to Atlantic Power Corporation	$ (0.03)	$ (0.29)	$ 0.11	$ (0.50)
Diluted				
Numerator:				
Net (loss) income attributable to Atlantic Power Corporation	$ (3.2)	$ (32.9)	$ 12.1	$ (57.5)
Add: convertible debenture interest expense	—	—	3.5	—
	(3.2)	(32.9)	15.6	(57.5)
Denominator:				
Weighted average basic shares outstanding	111.1	115.3	112.8	115.1
Convertible debentures	—	—	27.3	—
Share-based compensation	—	—	—	—
	111.1	115.3	140.1	115.1
Diluted (loss) earnings per share attributable to Atlantic Power Corporation	$ (0.03)	$ (0.29)	$ 0.11	$ (0.50)

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The following table summarizes our outstanding instruments that are anti-dilutive and were not included in the computation of our diluted (loss) earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Share-based compensation	2.2	2.1	2.2	2.1
Convertible debentures	29.1	8.1	—	8.1
Total	31.3	10.2	2.2	10.2

13. Equity

The following table provides a reconciliation of the beginning and ending equity attributable to shareholders of Atlantic Power Corporation, preferred shares issued by a subsidiary company and total equity for the nine months ended September 30, 2018 and 2017:

	Nine months ended September 30, 2018		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity

Balance at January 1, 2018	$ (18.4)	$ 215.2	$ 196.8
Net income (loss)	12.1	(1.6)	10.5
Realized and unrealized gain on hedging activities, net of tax	0.6	—	0.6
Foreign currency translation adjustment	(5.3)	—	(5.3)
Common share repurchases	(12.3)	—	(12.3)
Preferred share repurchases	—	(8.0)	(8.0)
Share-based compensation	1.8	—	1.8
Dividends declared on preferred shares of a subsidiary company	—	(6.3)	(6.3)
Balance at September 30, 2018	$ (21.5)	$ 199.3	$ 177.8

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	Nine months ended September 30, 2017		
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Total Equity
Balance at January 1, 2017	$ 64.6	$ 221.3	$ 285.9
Net (loss) income	(57.5)	3.5	(54.0)
Realized and unrealized gain on hedging activities, net of tax	0.2	—	0.2
Foreign currency translation adjustment	15.9	—	15.9
Defined benefit plan, net of tax	0.1	—	0.1
Common share repurchases	(0.2)	—	(0.2)
Preferred share repurchases	—	(3.1)	(3.1)
Share-based compensation	1.6	—	1.6
Dividends declared on preferred shares of a subsidiary company	—	(6.5)	(6.5)
Derecognition of noncontrolling interests upon sale of subsidiaries	—	—	—
Balance at September 30, 2017	$ 24.7	$ 215.2	$ 239.9

Share Repurchase Program

On December 29, 2016, we commenced a normal course issuer bid ("NCIB") for each series of our convertible unsecured subordinated debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. ("APPEL"), our wholly-owned subsidiary. The Board authorization permitted the Company to repurchase stock through open market repurchases. We repurchased a cumulative 0.1 million common shares at a total cost of $0.2 million before its expiration on December 28, 2017. Repurchases and retirement of common shares are recorded to common shares on the consolidated balance sheets.

On December 29, 2017, we commenced a new NCIB for our Series C and Series D Debentures, our common shares and for each series of the preferred shares of APPEL. The new NCIBs expire on December 28, 2018 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the new NCIBs, we may purchase up to a total of 11,308,946 common shares based on 10% of our public float as of December 15, 2017 and we are limited to daily purchases of 11,789 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the new NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the NYSE in compliance with Rule 10b-18 under the Exchange Act or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval. For the nine months ended September 30, 2018, we repurchased and cancelled 5.8 million common shares at a cost of $12.3 million.

On June 21, 2018, we amended the NCIBs to increase the number of 4.85% Cumulative Redeemable Preferred Shares, Series 1 (“Series 1 Preferred Shares”) that we may purchase to 475,000, representing approximately 10% of the 4,750,000 preferred shares public float as of December 15, 2017; increase the number of Cumulative Rate Reset Preferred Shares, Series 2 (“Series 2 Preferred Shares”) that we may purchase to 233,609, representing approximately 10% of the 2,338,094 preferred shares public float as of December 15, 2017; and increase the number of Cumulative Floating Rate Preferred Shares, Series 3 (“Series 3 Preferred Shares”) that we may purchase to 164,790, representing approximately 10% of the 1,661,906 preferred shares public float as of December 15, 2017. Daily repurchases are not affected by the amendment and each series will be limited to 1,000 preferred shares daily, other than block purchase exemptions.

Under the NCIBs, 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.

14. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We analyze the performance of our operating segments based on Project Adjusted EBITDA, which is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. We use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented as proportionately consolidated based on our ownership percentage in the reconciliation of Project Adjusted EBITDA to project income (loss).

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A reconciliation of Project Adjusted EBITDA to net income (loss) for the three and nine months ended September 30, 2018 and 2017 is included in the tables below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Three Months Ended September 30, 2018					
Project revenues	$ 36.3	$ 13.8	$ 15.1	$ 0.2	$ 65.4
Segment assets	607.2	182.2	194.9	74.3	1,058.6
Project Adjusted EBITDA	$ 25.5	$ 11.5	$ 8.3	$ 0.1	$ 45.4
Change in fair value of derivative instruments	0.5	—	(0.8)	0.3	—
Depreciation and amortization	11.6	5.5	7.9	—	25.0
Interest, net	0.7	(1.3)	—	—	(0.6)
Other project (income) expense	—	(5.3)	—	0.1	(5.2)
Project income (loss)	12.7	12.6	1.2	(0.3)	26.2
Administration	—	—	—	5.7	5.7
Interest expense, net	—	—	—	14.6	14.6
Foreign exchange loss	—	—	—	4.5	4.5
Other expense, net	—	—	—	2.5	2.5
Income (loss) before income taxes	12.7	12.6	1.2	(27.6)	(1.1)
Income tax expense	—	—	—	3.6	3.6
Net income (loss)	$ 12.7	$ 12.6	$ 1.2	$ (31.2)	$ (4.7)

	East U.S.	Canada	Un-Allocated Corporate	Consolidated

		West U.S.			
Three Months Ended September 30, 2017					
Project revenues	$ 39.8	$ 35.1	$ 33.5	$ 0.2	$ 108.6
Segment assets	680.9	237.5	281.9	113.6	1,313.9
Project Adjusted EBITDA	$ 30.6	$ 21.7	$ 24.6	$ 0.5	$ 77.4
Change in fair value of derivative instruments	1.3	—	1.3	(0.6)	2.0
Depreciation and amortization	11.8	10.6	14.0	0.2	36.6
Interest, net	2.5	—	—	—	2.5
Impairment	—	57.3	—	—	57.3
Other project income	—	—	(0.1)	—	(0.1)
Project income (loss)	15.0	(46.2)	9.4	0.9	(20.9)
Administration	—	—	—	5.5	5.5
Interest expense, net	—	—	—	13.8	13.8
Foreign exchange loss	—	—	—	9.4	9.4
Income (loss) before income taxes	15.0	(46.2)	9.4	(27.8)	(49.6)
Income tax benefit	—	—	—	(15.9)	(15.9)
Net income (loss)	$ 15.0	$ (46.2)	$ 9.4	$ (11.9)	$ (33.7)

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	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Nine Months Ended September 30, 2018					
Project revenues	$ 116.9	$ 35.7	$ 58.3	$ 0.7	$ 211.6
Segment assets	607.2	182.2	194.9	74.3	1,058.6
Project Adjusted EBITDA	$ 89.8	$ 16.9	$ 31.5	$ 0.3	$ 138.5
Change in fair value of derivative instruments	0.8	—	(2.2)	(2.1)	(3.5)
Depreciation and amortization	34.8	19.2	23.9	0.1	78.0
Interest, net	2.7	—	—	—	2.7
Other project income	—	(6.7)	—	—	(6.7)
Project income	51.5	4.4	9.8	2.3	68.0
Administration	—	—	—	17.9	17.9
Interest expense, net	—	—	—	40.7	40.7
Foreign exchange gain	—	—	—	(9.1)	(9.1)
Other expense, net	—	—	—	0.3	0.3
Net income (loss) before income taxes	51.5	4.4	9.8	(47.5)	18.2
Income tax expense	—	—	—	7.7	7.7
Net income (loss)	$ 51.5	$ 4.4	$ 9.8	$ (55.2)	$ 10.5

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Nine Months Ended September 30, 2017					
Project revenues	$ 116.3	$ 86.2	$ 127.8	$ 0.7	$ 331.0
Segment assets	680.9	237.5	281.9	113.6	1,313.9
Project Adjusted EBITDA	$ 86.8	$ 41.5	$ 97.3	$ 1.0	$ 226.6
	3.3	—	5.4	(2.9)	5.8

Change in fair value of derivative instruments					
Depreciation and amortization	34.2	30.6	40.4	0.4	105.6
Interest, net	8.0	—	—	—	8.0
Impairment	—	57.3	—	—	57.3
Other project expense (income)	57.7	—	(0.1)	—	57.6
Project (loss) income	(16.4)	(46.4)	51.6	3.5	(7.7)
Administration	—	—	—	17.6	17.6
Interest expense, net	—	—	—	49.5	49.5
Foreign exchange loss	—	—	—	17.7	17.7
Net (loss) income before income taxes	(16.4)	(46.4)	51.6	(81.3)	$ (92.5)
Income tax benefit	—	—	—	(38.5)	(38.5)
Net (loss) income	$ (16.4)	$ (46.4)	$ 51.6	$ (42.8)	$ (54.0)

The table below provides information, by country, about our consolidated operations for each of the three and nine months ended September 30, 2018 and 2017 and Property, Plant & Equipment as of September 30, 2018 and December 31, 2017, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

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	Project Revenue Three Months Ended September 30,		Project Revenue Nine Months Ended September 30,		Property, Plant and Equipment, net of accumulated depreciation	
	2018	2017	2018	2017	September 30, 2018	December 31, 2017
United States	$ 50.3	$ 75.1	$ 153.3	$ 203.2	$ 404.1	$ 426.2
Canada	15.1	33.5	58.3	127.8	163.8	176.1
Total	$ 65.4	$ 108.6	$ 211.6	$ 331.0	$ 567.9	$ 602.3

Concentration risk

Georgia Power Company, Southern California Edison and Equistar Chemicals, LP provided 17.2%, 12.7% and 12.4%, respectively, of total consolidated revenues for the three months ended September 30, 2018. Independent Electricity System Operator (“IESO”), San Diego Gas & Electric (“SDG&E”), BC Hydro and Georgia Power Company provided 16.4%, 13.9%, 11.3% and 10.3%, respectively, of total consolidated revenues for the three months ended September 30, 2017. Niagara Mohawk, BC Hydro, Georgia Power Company and Equistar Chemicals, LP provided 13.8%, 12.6%, 12.0% and 11.8%, respectively, of total consolidated revenues for the nine months ended September 30, 2018. IESO, SDG&E, Niagara Mohawk and BC Hydro provided 19.3%, 11.1%, 10.7% and 10.3%, respectively, of total consolidated revenues for the nine months ended September 30, 2017. Georgia Power Company purchases electricity from the Piedmont project in the East U.S. segment, Southern California Edison purchases electricity from the Oxnard project in the West U.S. segment, Niagara Mohawk purchases electricity from the Curtis Palmer project in the East U.S. segment, Equistar Chemicals, LP purchases electricity from the Morris project in the East U.S. segment, and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment.

15. Guarantees and Contingencies

Guarantees

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

Contingencies

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of September 30, 2018.

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FORWARD LOOKING INFORMATION

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

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

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

Forward looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under “Item 1A. Risk Factors” in our Annual Report on Form 10 K for the year ended December 31, 2017 and in this Quarterly

Report on Form 10 Q. To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2017 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updates to our business strategy, such risk factors should be read in light of such information. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

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

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

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

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- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our senior secured term loans;
- exchange rate fluctuations;
- the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;
- unstable capital and credit markets;
- the dependence of our projects on their electricity and thermal energy customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- the dependence of our projects on third-party suppliers;
- projects not operating according to plan;
- the effects of weather, which affects demand for electricity and fuel as well as operating conditions;
- U.S., Canadian and/or global economic conditions and uncertainty;
- risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;
- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- the impact of impairment of goodwill, long lived assets or equity method investments;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority owned projects;

· transfer restrictions on our equity interests in certain projects;

· risks inherent in the use of derivative instruments;

· labor disruptions;

· the impact of hostile cyber intrusions;

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

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

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

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

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

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

OVERVIEW

Atlantic Power 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.

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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 the 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.

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Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rati (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		Biomass	66	100.00 %	66		June 2019	AAA

	British Columbia					British Columbia Hydro and Power Authority		
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

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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;

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· 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:

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· 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.

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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				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	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				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	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,

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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.

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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.

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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	

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	Nine months ended September 30, 2018				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	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				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	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.

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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.

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Project Operating Performance

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

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· 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.

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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.

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Project Adjusted EBITDA

	Three months ended September 30,		$ change 2018 vs	Nine months ended September 30,		$ change 2018 vs
	2018	2017	2017	2018	2017	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	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.

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	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) %

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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.

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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,	
			% change
	2018	2017	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,	
			% change
	2018	2017	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.

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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.

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· 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.

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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.

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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 F
are effective.

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Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the nine months ended September 30, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent material errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the control may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

ITEM 1A. RISK FACTORS

There were no material changes to the risk factors disclosed in “Item 1A. Risk Factors” of our Annual Report on Form 10 K for the year ended December 31, 2017 except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10 Q relates to such risk factors (including, without limitation, the matters discussed in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations”). To the extent any risk factors in our Annual Report on Form 10 K for the year ended December 31, 2017 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10 Q, including with respect to our business plan and any updated to our business strategy, such risk factors should be read in light of such information.

ITEM 2: UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEED

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

Share Repurchase Program

On December 29, 2017, we commenced an NCIB for each of our Series C and Series D Debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. The NCIB expires on

December 28, 2018 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIBs. Under the NCIB, we may purchase up to a total of 11,308,946 common shares based on 10% of our public float as of December 15, 2017 and we are limited to daily purchases of 11,789 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. On June 21, 2018, we amended the NCIB to increase the number of the Series 1 Preferred Shares that we may purchase to 475,000, representing approximately 10% of the 4,750,000 preferred shares public float as of December 15, 2017; increase the number of Series 2 Preferred Shares that we may purchase to 233,609, representing approximately 10% of the 2,338,094 preferred shares public float as of December 15, 2017; and increase the number of Series 3 Preferred Shares that we may purchase to 164,790, representing approximately 10% of the 1,661,906 preferred shares public float as of December 15, 2017. Daily repurchases are not affected by the amendment and each series will be limited to 1,000 preferred shares daily, other than block purchase exemptions.

Through September 30, 2018, we repurchased and cancelled approximately 5.8 million shares at a cost of $12.3 million. We also repurchased and cancelled approximately 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, for a total payment of Cdn$10.3 million in the nine months ended September 30, 2018.

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The following table provides purchases of common equity securities by the Issuer and Affiliated Purchases for the period of July 1, 2018 through September 30, 2018:

Purchase Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares as Part of a Publicly Announced Purchase Plan	Dollar Value of Maximum Number of Shares to be Purchased Under the Plan
7/1/2018 - 7/31/2018	299,348	$ 2.14	299,348	
8/1/2018 - 8/31/2018	569,027	$ 2.15	569,027	
9/1/2018 - 9/30/2018	570,330	$ 2.15	570,330	$11,885,948(1)
Total	1,438,705		1,438,705	

(1) Under the NCIB, we may purchase up to a total of 11,308,946 Common shares. Through September 30, 2018, we have repurchased a cumulative 5,780,598 shares and we are authorized to purchase up to an additional 5,528,348 Common shares under the NCIB. Our plan does not obligate the Company to acquire any specific number of shares. The $11.9 million dollar value of maximum number of shares that may be purchased under the plan is based on the $2.15 average share price for the month of September 2018.

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.2*	Fourth Amendment dated October 31, 2018 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a 14(a) or Rule 15d 14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

*Filed herewith.

**Furnished herewith.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: November 1, 2018	Atlantic Power Corporation
	By: /s/ Terrence Ronan
	Name: Terrence Ronan
	Title: Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)