ATLANTIC POWER CORP
Form 10-Q
August 07, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2014

OR

o **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 (State or other jurisdiction of incorporation or organization)	**55-0886410** (I.R.S. Employer Identification No.)
One Federal Street, 30th Floor **Boston, MA** (Address of principal executive offices)	**02110** (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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ý No o

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

Large accelerated filer o	Accelerated filer ý	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The number of shares outstanding of the registrant's Common Stock as of August 7, 2014 was 120,712,916.

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ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND SIX MONTHS ENDED JUNE 30, 2014

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GENERAL

In this Quarterly Report on Form 10-Q, references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$" and "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)

	June 30, 2014 (unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 157.6	$ 158.6
Restricted cash	17.8	96.2
Accounts receivable	61.5	64.3
Current portion of derivative instruments asset (Notes 7 and 8)	1.7	0.2
Inventory	18.6	16.0
Prepayments and other current assets	15.4	16.1
Refundable income taxes	2.1	4.0
Total current assets	274.7	355.4
Property, plant, and equipment, net of accumulated depreciation of $241.2 million and $175.1 million at June 30, 2014 and December 31, 2013, respectively	1,751.2	1,813.4
Equity investments in unconsolidated affiliates (Note 4)	368.5	394.3
Other intangible assets, net of accumulated amortization of $177.0 million and $136.9 million at June 30, 2014 and December 31, 2013, respectively	420.6	451.5
Goodwill (Note 5)	291.1	296.3
Derivative instruments asset (Notes 7 and 8)	6.3	13.0
Other assets	98.3	71.1
Total assets	$ 3,210.7	$ 3,395.0
Liabilities		
Current liabilities:		
Accounts payable	$ 10.5	$ 14.0
Accrued interest	6.3	17.7
Other accrued liabilities	48.9	58.8
Current portion of long-term debt (Note 6)	26.4	216.2
Current portion of convertible debentures	42.0	42.1
Current portion of derivative instruments liability (Notes 7 and 8)	28.4	28.5
Dividends payable	3.8	6.8
Other current liabilities	8.1	5.3
Total current liabilities	174.4	389.4
Long-term debt (Note 6)	1,436.0	1,254.8
Convertible debentures	362.4	363.1
Derivative instruments liability (Notes 7 and 8)	58.2	76.1
Deferred income taxes (Note 9)	95.7	111.5
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $9.9 million and $8.1 million at June 30, 2014 and December 31, 2013, respectively	36.9	38.7
Other non-current liabilities	63.2	65.4
Commitments and contingencies (Note 16)		

Total liabilities		2,226.8		2,299.0
Equity				
Common shares, no par value, unlimited authorized shares; 120,712,916 and 120,205,813 issued and outstanding at June 30, 2014 and December 31, 2013, respectively (Note 13)		1,286.5		1,286.1
Preferred shares issued by a subsidiary company (Note 13)		221.3		221.3
Accumulated other comprehensive loss		(24.1)		(22.4)
Retained deficit		(754.3)		(655.4)
Total Atlantic Power Corporation shareholders' equity		729.4		829.6
Noncontrolling interests (Note 13)		254.5		266.4
Total equity		983.9		1,096.0
Total liabilities and equity	$	3,210.7	$	3,395.0

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 June 30,		Six months ended June 30,	
	2014	**2013**	**2014**	**2013**
Project revenue:				
Energy sales	$ 82.4	$ 76.9	$ 164.7	$ 153.8
Energy capacity revenue	41.3	42.9	74.8	77.2
Other	19.5	16.3	49.0	42.6
	143.2	136.1	288.5	273.6
Project expenses:				
Fuel	50.4	50.0	110.2	97.7
Operations and maintenance	34.5	46.4	67.2	73.9
Development	1.1	1.8	1.8	3.5
Depreciation and amortization	40.9	41.8	81.5	82.7
	126.9	140.0	260.7	257.8
Project other income (expense):				
Change in fair value of derivative instruments (Notes 7 and 8)	(2.8)	24.3	11.9	36.9
Equity in earnings of unconsolidated affiliates (Note 4)	3.3	8.7	11.9	15.9
Interest expense, net	(5.8)	(8.8)	(20.4)	(16.8)
Impairment	(14.8)		(14.8)	
	(20.1)	24.2	(11.4)	36.0
Project (loss) income	(3.8)	20.3	16.4	51.8
Administrative and other expenses (income):				
Administration	10.2	11.8	17.5	20.1
Interest, net	27.7	25.3	94.1	51.2
Foreign exchange loss (gain) (Note 8)	15.3	(14.5)	(1.5)	(22.0)
Other income, net (Note 3)		(9.5)	(2.1)	(9.5)
	53.2	13.1	108.0	39.8
(Loss) income from continuing operations before income taxes	(57.0)	7.2	(91.6)	12.0
Income tax (benefit) expense (Note 9)	(0.6)	0.6	(12.9)	(1.9)
(Loss) income from continuing operations	(56.4)	6.6	(78.7)	13.9
Net loss from discontinued operations, net of tax (Note 12)		(5.4)	(0.1)	(4.9)

Net (loss) income		(56.4)		1.2		(78.8)		9.0
Net (loss) income attributable to noncontrolling interests		(0.3)		1.1		(6.7)		(0.8)
Net income attributable to preferred shares dividends of a subsidiary company		3.1		3.1		5.9		6.3
Net (loss) income attributable to Atlantic Power Corporation	$	(59.2)	$	(3.0)	$	(78.0)	$	3.5
Basic earnings per share: (Note 11)								
(Loss) income from continuing operations attributable to Atlantic Power Corporation	$	(0.49)	$	0.02	$	(0.65)	$	0.07
Loss from discontinued operations, net of tax				(0.05)				(0.04)
Net loss attributable to Atlantic Power Corporation	$	(0.49)	$	(0.03)	$	(0.65)	$	0.03
Diluted earnings per share: (Note 11)								
(Loss) income from continuing operations attributable to Atlantic Power Corporation	$	(0.49)	$	0.02	$	(0.65)	$	0.07
Loss from discontinued operations, net of tax				(0.05)				(0.04)
Net (loss) income attributable to Atlantic Power Corporation	$	(0.49)	$	(0.03)	$	(0.65)	$	0.03
Weighted average number of common shares outstanding: (Note 11)								
Basic		120.6		119.9		120.5		119.7
Diluted		120.6		119.9		120.5		120.3

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 June 30,	
	2014	2013
Net (loss) income	$ (56.4)	$ 1.2
Other comprehensive (loss) income, net of tax:		
Unrealized (loss) income on hedging activities	$ (0.3)	$ 0.6
Net amount reclassified to earnings	0.1	0.1
Net unrealized (loss) gain on derivatives	(0.2)	0.7
Foreign currency translation adjustments	17.3	(18.0)
Other comprehensive income (loss), net of tax	17.1	(17.3)
Comprehensive loss	(39.3)	(16.1)
Less: Comprehensive income attributable to noncontrolling interests	2.8	4.2
Comprehensive loss attributable to Atlantic Power Corporation	$ (42.1)	$ (20.3)

	Six months ended June 30,	
	2014	2013
Net (loss) income	$ (78.8)	$ 9.0
Other comprehensive (loss) income, net of tax:		
Unrealized (loss) income on hedging activities	$ (0.7)	$ 0.6
Net amount reclassified to earnings	0.4	0.4
Net unrealized (loss) gain on derivatives	(0.3)	1.0
Foreign currency translation adjustments	(1.4)	(30.1)

Other comprehensive loss, net of tax		(1.7)		(29.1)
Comprehensive loss		(80.5)		(20.1)
Less: Comprehensive (loss) income attributable to noncontrolling interests		(0.8)		5.5
Comprehensive loss attributable to Atlantic Power Corporation	$	(79.7)	$	(25.6)

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)

	Six months ended June 30, 2014	Six months ended June 30, 2013
Cash flows from operating activities:		
Net (loss) income	$ (78.8)	$ 9.0
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	81.5	92.8
Loss of discontinued operations		32.8
Gain on sale of asset	(2.1)	(4.4)
Long-term incentive plan expense	0.9	1.2
Impairment charges	14.8	4.9
Equity in earnings from unconsolidated affiliates	(11.9)	(15.9)
Distributions from unconsolidated affiliates	37.8	18.0
Unrealized foreign exchange gain	(1.4)	(8.7)
Change in fair value of derivative instruments	(11.9)	(47.7)
Change in deferred income taxes	(15.5)	(6.5)
Change in other operating balances		
Accounts receivable	2.8	(3.6)
Inventory	(2.6)	(1.3)
Prepayments, refundable income taxes and other assets	14.7	46.3
Accounts payable	(4.6)	(9.4)
Accruals and other liabilities	(18.2)	(10.6)
Cash provided by operating activities	5.5	96.9
Cash flows provided by investing activities:		
Change in restricted cash	78.4	(19.4)
Proceeds from sale of asset, net	1.0	148.3
Proceeds from treasury grant		53.7
Biomass development costs		(0.1)
Construction in progress	(1.5)	(28.5)
Purchase of property, plant and equipment	(2.5)	(2.7)
Cash provided by investing activities	75.4	151.3
Cash flows used in financing activities:		
Proceeds from senior secured term loan facility	600.0	
Proceeds from project-level debt		20.8
Repayment of corporate and project-level debt	(608.0)	(64.2)
Payments for revolving credit facility borrowings		(67.0)
Deferred financing costs	(38.8)	
Equity contribution from noncontrolling interest		44.6
Offering costs related to tax equity		(1.0)
Dividends paid to common shareholders	(20.9)	(43.2)
Dividends paid to noncontrolling interests	(14.2)	(9.3)
Cash used in financing activities	(81.9)	(119.3)
Net (decrease) increase in cash and cash equivalents	(1.0)	128.9

Cash and cash equivalents at beginning of period at discontinued operations				6.5
Cash and cash equivalents at beginning of period		158.6		60.2
Cash and cash equivalents at end of period	$	157.6	$	195.6
Supplemental cash flow information				
Interest paid	$	114.7	$	65.3
Income taxes paid, net	$	1.0	$	1.4
Accruals for construction in progress	$	8.2	$	8.6

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

(Unaudited)

1. Nature of business and basis of presentation

Nature of business

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of June 30, 2014, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,945 megawatts ("MW") in which our aggregate ownership interest is approximately 2,024 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") which we sold in a transaction that closed in July 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer based in Seattle, Washington. Twenty of our projects are majority-owned subsidiaries.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at One Federal Street, 30th Floor, Boston, Massachusetts 02110, USA. Our telephone number in Boston 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 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, 2013. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of June 30, 2014, the results of operations and comprehensive income (loss) for the three and six months ended June 30, 2014 and 2013, and our cash flows for the six months ended June 30, 2014 and 2013. In the opinion of management, all adjustments

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

1. Nature of business and basis of presentation (Continued)

(consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

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 values of acquired assets, 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 the allocation of taxable income and losses, tax credits and cash distributions using the hypothetical liquidation book value ("HLBV") method. 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, 2013. 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.

Reclassifications

Certain prior year amounts have been reclassified to conform to the current period presentation.

Recently issued accounting standards

Adopted

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. These changes became effective for us on January 1, 2014 and did not have a material impact on the consolidated financial statements.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

1. Nature of business and basis of presentation (Continued)

In March 2013, the FASB issued changes to a parent entity's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity. A parent entity is required to release any related cumulative foreign currency translation adjustment from accumulated other comprehensive income (loss) into net income (loss) in the following circumstances: (i) a parent entity ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity if the sale or transfer results in the complete or substantially complete liquidation of the foreign entity in which the subsidiary or group of assets had resided; (ii) a partial sale of an equity method investment that is a foreign entity; (iii) a partial sale of an equity method investment that is not a foreign entity whereby the partial sale represents a complete or substantially complete liquidation of the foreign entity that held the equity method investment; and (iv) the sale of an investment in a foreign entity. These changes became effective for us on January 1, 2014 and did not have a material impact on the consolidated financial statements.

In February 2013, the FASB issued changes to the accounting for obligations resulting from joint and several liability arrangements. These changes require an entity to measure such obligations for which the total amount of the obligation is fixed at the reporting date as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors, and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. An entity will also be required to disclose the nature and amount of the obligation as well as other information about those obligations. Examples of obligations subject to these requirements are debt arrangements and settled litigation and judicial rulings. These changes became effective for us on January 1, 2014 and did not have a material impact on the consolidated financial statements.

On January 1, 2013, we adopted changes issued by the FASB to the reporting of amounts reclassified out of accumulated other comprehensive income (loss). These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income (loss) on the respective line items in net income (loss) if the amount being reclassified is required to be reclassified in its entirety to net income (loss). For other amounts that are not required to be reclassified in their entirety to net income (loss) in the same reporting period, an entity is required to cross-reference other disclosures that provide additional detail about those amounts. These requirements are to be applied to each component of accumulated other comprehensive income (loss). Other than the additional disclosure requirements (see below), the adoption of these changes had no impact on the consolidated financial statements.

Issued

In April 2014, the FASB issued changes to reporting discontinued operations and disclosures of disposals of components of an entity. These changes require a disposal of a component to meet a higher threshold in order to be reported as a discontinued operation in an entity's financial statements. The threshold is defined as a strategic shift that has, or will have, a major effect on an entity's operations and financial results such as a disposal of a major geographical area or a major line of business. Additionally, the following two criteria have been removed from consideration of whether a component meets the requirements for discontinued operations presentation: (i) the operations and

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

1. Nature of business and basis of presentation (Continued)

cash flows of a disposal component have been or will be eliminated from the ongoing operations of an entity as a result of the disposal transaction, and (ii) an entity will not have any significant continuing involvement in the operations of the disposal component after the disposal transaction. Furthermore, equity method investments now may qualify for discontinued operations presentation. These changes also require expanded disclosures for all disposals of components of an entity, whether or not the threshold for reporting as a discontinued operation is met, related to profit or loss information and/or asset and liability information of the component. These changes become effective on January 1, 2015. The adoption of these changes will not have an immediate impact on the consolidated financial statements. This guidance will need to be considered in the event that we initiate a disposal transaction.

In May 2014, the FASB issued changes to the recognition of revenue from contracts with customers. These changes created a comprehensive framework for all entities in all industries to apply in the determination of when to recognize revenue, and, therefore, supersede virtually all existing revenue recognition requirements and guidance. This framework is expected to result in less complex guidance in application while providing a consistent and comparable methodology for revenue recognition. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this principle, an entity should apply the following steps: (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. These changes become effective on January 1, 2017. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

2. Changes in accumulated other comprehensive loss by component

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

	Three months ended June 30,	
	2014	**2013**
Foreign currency translation		
Balance at beginning of period	$ (40.9)	$ 0.5
Other comprehensive income (loss):		
Foreign currency translation adjustments[1]	17.3	(18.0)
Balance at end of period	$ (23.6)	$ (17.5)
Pension		
Balance at beginning of period	$ (0.4)	$ (1.8)
Other comprehensive loss:		
Amortization of net actuarial gain		
Balance at end of period	$ (0.4)	$ (1.8)
Cash flow hedges		
Balance at beginning of period	$ 0.1	$ (1.1)
Other comprehensive (loss) income:		
Net change from periodic revaluations	(0.5)	1.0
Tax benefit (expense)	0.2	(0.4)
Total Other comprehensive income (loss) before reclassifications, net of tax	(0.3)	0.6
Net amount reclassified to earnings (loss):		
Interest rate swaps[2]	0.3	0.4
Fuel commodity swaps[3]		(0.1)
Sub-total	0.3	0.3
Tax expense	0.2	0.2
Total amount reclassified from Accumulated other comprehensive loss, net of tax	0.1	0.1
Total Other comprehensive (loss) income	(0.2)	0.7

Balance at end of period	$	(0.1)	$	(0.4)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

2. Changes in accumulated other comprehensive loss by component (Continued)

	Six months ended June 30, 2014	Six months ended June 30, 2013
Foreign currency translation		
Balance at beginning of period	$ (22.2)	$ 12.6
Other comprehensive loss:		
Foreign currency translation adjustments[1]	(1.4)	(30.1)
Balance at end of period	$ (23.6)	$ (17.5)
Pension		
Balance at beginning of period	$ (0.4)	$ (1.8)
Other comprehensive loss:		
Amortization of net actuarial gain		
Balance at end of period	$ (0.4)	$ (1.8)
Cash flow hedges		
Balance at beginning of period	$ 0.2	$ (1.4)
Other comprehensive (loss) income:		
Net change from periodic revaluations	(1.1)	1.0
Tax benefit (expense)	0.4	(0.4)
Total Other comprehensive (loss) income before reclassifications, net of tax	(0.7)	0.6
Net amount reclassified to earnings (loss):		
Interest rate swaps[2]	0.7	0.8
Fuel commodity swaps[3]		(0.2)
Sub-total	0.7	0.6
Tax expense	0.3	0.2
Total amount reclassified from Accumulated other comprehensive loss, net of tax	0.4	0.4
Total Other comprehensive (loss) income	(0.3)	1.0

Balance at end of period	$	(0.1)	$	(0.4)

(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) A positive amount indicates a corresponding charge to earnings (loss) and a negative amount indicates a corresponding benefit to earnings (loss). These amounts were reflected on the accompanying consolidated statements of operations in the line items indicated in footnotes 1 and 2.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

3. Acquisitions and divestments

2014 Divestments

(a)
Delta-Person

In December 2012, we and the owners of Delta-Person, entered into a purchase and sale agreement with BHB Power, LLC and Public Service Company of New Mexico to sell the project for approximately $37.2 million including working capital adjustments. We received net cash proceeds in July 2014 for our ownership interest of approximately $7.2 million in the aggregate. We expect to receive an additional $1.4 million of cash proceeds held in escrow for up to twelve months after the close of the transaction. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Delta-Person closed in July 2014 resulting in a gain on sale of approximately $8.6 million that will be recorded as a component of other income in the consolidated statement of operations for the three months ended September 30, 2014.

(b)
Greeley

In March 2014, we closed a transaction with Initium Power Partners, LLC. ("Initium"), whereby Initium agreed to purchase all of the issued and outstanding membership interests in Greeley for approximately $1.0 million. We recorded a $2.1 million non-cash gain on the sale in the consolidated statement of operations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the six months ended June 30, 2014.

2013 Divestments

(a)
Gregory

In April 2013, we and the other owners of Gregory, entered into a purchase and sale agreement with an affiliate of NRG Energy, Inc. to sell the project for approximately $274.2 million including working capital adjustments. We received net cash proceeds for our ownership interest of approximately $34.6 million in the aggregate, after repayment of project-level debt and transaction expenses. Approximately $5.0 million of these proceeds will be held in escrow for up to one year after the closing date. We used the net proceeds from the sale for general corporate purposes. The sale of Gregory closed in August 2013 resulting in a gain on sale of approximately $31.0 million, which was recorded as a component of other income in the consolidated statement of operations for the three months ended September 30, 2013.

(b)
Auburndale, Lake and Pasco

In January 2013, we entered into a purchase and sale agreement for the sale of our Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") for approximately $140.0 million, with working capital adjustments. The sale closed in April 2013 and we received net cash proceeds of approximately $117.0 million in the aggregate, after repayment of project-level debt at Auburndale and settlement of all outstanding natural gas swap agreements at Lake and Auburndale. This includes approximately $92.0 million received at closing and cash distributions from the Florida Projects of approximately $25.0 million received since January 1, 2013. We used a portion of the net proceeds from the sale to fully repay our senior credit facility, which had an outstanding balance of approximately $64.1 million

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

3. Acquisitions and divestments (Continued)

on the closing date. The remaining cash proceeds were used for general corporate purposes. The Florida Projects were accounted for as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013. See Note 12, *Discontinued Operations*, for further information.

(c) Path 15

In March 2013, we entered into a purchase and sales agreement with Duke Energy Corporation and American Transmission Co., to sell our interests in the Path 15 transmission line ("Path 15"). The sale closed on April 30, 2013 and we received net cash proceeds from the sale, including working capital adjustments, of approximately $52.0 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56.0 million. The cash proceeds were used for general corporate purposes. All project level debt issued by Path 15, totaling $137.2 million, transferred with the sale. Path 15 was accounted for as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013. See Note 12, *Discontinued Operations*, for further information.

4. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three and six months ended June 30, 2014 and 2013, respectively, for earnings in our equity method investments:

	Three months ended June 30,		Six months ended June 30,	
Operating results	**2014**	**2013**	**2014**	**2013**
Revenue				
Chambers	$ 12.6	$ 13.4	$ 30.6	$ 26.6
Other[1]	33.5	41.2	73.2	80.6
	46.1	54.6	103.8	107.2
Project expenses				
Chambers	10.8	11.1	25.1	20.7
Other[1]	28.8	34.5	61.4	68.1
	39.6	45.6	86.5	88.8
Project other expense				
Chambers	(1.5)	(0.6)	(2.1)	(1.2)
Other[1]	(1.7)	0.3	(3.3)	(1.3)
	(3.2)	(0.3)	(5.4)	(2.5)
Project income				
Chambers	$ 0.3	$ 1.7	$ 3.4	$ 4.7

Other[1]	3.0	7.0	8.5	11.2
	3.3	8.7	11.9	15.9

(1) Includes equity method investments that individually do not exceed 10% of consolidated total assets or income (loss) before income taxes.

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

(Unaudited)

5. Goodwill

Our goodwill balance was $291.1 million and $296.3 million as of June 30, 2014 and December 31, 2013, respectively. We recorded $331.1 million of goodwill in connection with the acquisition of Capital Power Income L.P. (the "Partnership") in 2011. We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is at the project level and, the lowest level below the operating segments for which discrete financial information is available. For reporting units that fail step 1 of the goodwill impairment test, we will initiate a step 2 test to quantify the amount, if any, of non-cash impairment to record.

Under our accounting policies for long-lived assets and goodwill impairment, we also perform an impairment analysis at the earlier of (i) executing a new PPA (or other arrangement) and (ii) six months prior to the expiration of an existing PPA. The Tunis project's PPA expires on December 31, 2014 and accordingly, we performed a long-lived assets impairment test and a goodwill impairment test as of June 30, 2014.

Based on the results of our long-lived asset impairment test, it was determined that the weighted average estimated undiscounted cash flows for Tunis over its remaining useful life did not exceed the carrying value of the property, plant and equipment at the Tunis reporting unit. As a result, the project recorded a $9.6 million long-lived asset impairment charge in the three months ended June 30, 2014 which was the difference between the carrying value of the project's property, plant and equipment and its estimated fair market value.

Subsequent to adjusting the carrying value of the Tunis reporting unit for the $9.6 million long-lived asset impairment, we performed an impairment analysis for the project's goodwill. The project failed step 1 of the impairment test because the weighted average estimated discounted cash flows over its remaining useful life did not exceed the carrying value of the Tunis reporting unit. We performed step 2 of the goodwill impairment test and wrote off all of the projects goodwill because the carrying value of goodwill exceeded its implied fair value. As a result, Tunis, a component of the East segment, recorded a $5.2 million goodwill impairment charge in the three months ended June 30, 2014. The implied fair value of goodwill was determined in the same manner as the value of goodwill is determined in a business combination, using the fair value of the reporting unit as if it were the purchase price.

The total $14.8 million long-lived asset and goodwill impairment was primarily due to our assessment of the forecasted cash flows from re-contracting and other strategic outcomes.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our long-lived asset recovery and step 1 goodwill impairment tests for Tunis were determined using our best estimate of the weighted average probability of several re-contracting

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

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5. Goodwill (Continued)

scenarios and other strategic outcomes. The fair value of Tunis used to calculate the long-lived asset impairment amount and to perform step 2 of the goodwill impairment test was determined using market participant assumptions. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements.

The valuations of long-lived assets and goodwill for the long-lived assets and goodwill impairment analyses are considered level 3 fair value measurements, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities.

The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows and based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources.

Based on the continued deficit of our market capitalization as compared to our book carrying value, we determined that it was appropriate to initiate a test of the remaining goodwill at our reporting units to determine if it is more likely than not that the fair value of our reporting units do not exceed their carrying amounts. For reporting units, if any, that fail step 1 of the goodwill impairment test, we will initiate a step 2 test to quantify the amount, if any, of non-cash impairment to record. As of the date of this Quarterly Report on Form 10-Q, we are currently gathering the necessary information to perform these tests and expect to complete them during the three months ended September 30, 2014.

The following table is a rollforward of goodwill for the six months ended June 30, 2014:

(in millions)	East	West	Wind	Un-allocated corporate	Total
Balance at December 31, 2013	$ 107.8	$ 188.5	$	$	$ 296.3
Impairment of Goodwill	(5.2)				(5.2)
Balance at June 30, 2014	$ 102.6	$ 188.5	$	$	$ 291.1

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

(Unaudited)

6. Long-term debt

Long-term debt consists of the following:

	June 30, 2014	December 31, 2013	Interest Rate	
Recourse Debt:				
Senior secured term loan facility, due 2021	$ 562.5	$	LIBOR(1) plus 3.8%	
Senior unsecured notes, due 2018(2)	319.9	460.0	9.0%	
Senior unsecured notes, due June 2036 (Cdn$210.0)	196.8	197.4	6.0%	
Senior unsecured notes, due July 2014(3)		190.0	5.9%	
Series A senior unsecured notes, due August 2015(3)		150.0	5.9%	
Series B senior unsecured notes, due August 2017(3)		75.0	6.0%	
Non-Recourse Debt:				
Epsilon Power Partners term facility, due 2019	28.0	30.5	LIBOR plus 3.1%	
Cadillac term loan, due 2025	34.4	35.4	6.0%	8.0%
Piedmont term loan, due 2018(4)	68.3	76.6	5.2%	
Meadow Creek term loan, due 2024	167.3	169.8	2.9%	5.6%
Rockland term loan, due 2027	84.4	85.3	6.4%	
Other long-term debt	0.8	1.0	5.5%	6.7%
Less: current maturities	(26.4)	(216.2)		
Total long-term debt	$ 1,436.0	$ 1,254.8		

Current maturities consist of the following:

	June 30, 2014	December 31, 2013	Interest Rate	
Current Maturities:				
Senior secured term loan facility, due 2021	$ 6.0	$	LIBOR(1) plus 3.8%	
Senior unsecured notes, due July 2014(3)		190.0	5.9%	
Epsilon Power Partners term facility, due 2019	5.3	5.0	LIBOR plus 3.1%	
Cadillac term loan, due 2025	3.6	2.0	6.0%	8.0%
Piedmont term loan, due 2018(4)	4.9	12.6	5.2%	
Meadow Creek term loan, due 2024	4.8	4.9	2.9%	5.6%
Rockland term loan, due 2027	1.6	1.5	6.4%	
Other short-term debt	0.2	0.2	5.5	6.7%
Total current maturities	$ 26.4	$ 216.2		

(1) LIBOR cannot be less than 1.00%. On May 5, 2014 we entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $199.0 million notional amount of the $568.5 million outstanding aggregate borrowings. See Note 8, Accounting for derivative instruments and hedging activities for further details.

(2) We repurchased approximately $140.1 million aggregate principal amount of the 9.0% Notes in March 2014 with a portion of the proceeds from the New Senior Secured Credit Facilities and cash on hand, as further described below.

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

(Unaudited)

6. Long-term debt (Continued)

(3) The Curtis Palmer Notes due July 2014, Series A senior guaranteed notes due August 2015 and Series B senior guaranteed notes due August 2017 were retired on February 26, 2014 with proceeds from the New Senior Secured Credit Facilities described below.

(4) On February 14, 2014, we paid down $8.1 million of principal on the Piedmont construction loan and converted the remaining $68.5 million to a term loan due August 2018.

New Senior Secured Credit Facilities

On February 24, 2014, Atlantic Power Limited Partnership ("the Partnership"), our wholly-owned indirect subsidiary, entered into a new senior secured term loan facility (the "New Term Loan Facility"), comprising of $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "New Revolving Credit Facility") with a capacity of $210 million (collectively, the "New Senior Secured Credit Facilities"). Borrowings under the New Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate (LIBOR), the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the New Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively and was 3.75% at June 30, 2014. The Adjusted Eurodollar Rate cannot be less than 1.00% (1.00% at June 30, 2014). As further described in Note 8, the Partnership entered into interest rate swap agreements on May 5, 2014 to mitigate the exposure to changes in the Adjusted Eurodollar Rate for a portion of the New Term Loan Facility.

In connection with the funding of the New Senior Secured Credit Facilities, we terminated our prior revolving credit facility on February 26, 2014.

The New Term Loan Facility matures on February 24, 2021. The revolving commitments under the New Revolving Credit Facility terminate on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the New Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit.

The New Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The New Senior Secured Credit Facilities are not otherwise guaranteed or secured by us or any of our subsidiaries (other than the Partnership subsidiary guarantors). The New Senior Secured Credit Facilities have a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The debt service reserve requirement was funded with a $15.8 million letter of credit.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

6. Long-term debt (Continued)

The Partnership's existing Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership has granted an equal and ratable security interest in the collateral package securing the New Senior Secured Credit Facilities under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the New Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement also contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the New Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

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6. Long-term debt (Continued)

On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144.1 million ($107.0 million as of June 30, 2014) were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used to (i) satisfy a debt service reserve requirement in an amount equivalent to six months of debt service (approximately $15.8 million) and (ii) support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility under the New Senior Secured Credit Facilities to:

- redeem in whole, at a price equal to par plus $31.1 million of accrued interest and make-whole premiums (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 (the "Series A Notes") and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 (the "Series B Notes") issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses of approximately $40.0 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and

- make a distribution to us in the amount of $122 million which was used, in addition to cash on hand, to repurchase $140.1 million aggregate principal amount of the 9.0% Notes (as defined below) of Atlantic Power Corporation, make $15.7 million in accrued interest and premium payments as part of the aggregate repurchase price, and $0.1 million in commission fees associated with the repurchases.

In connection with the termination of our prior credit facility, we terminated the interest rate swap at Epsilon Power Partners, a wholly owned subsidiary, a portion of our natural gas swaps at Orlando and foreign exchange forward contracts at the Partnership. As a result of the termination of these contracts, we recorded $2.6 million of interest expense, $4.0 million of fuel expense and $0.4 million of foreign exchange loss, respectively.

The prior credit facility contained certain guaranties, which were terminated in connection with the termination of the prior credit facility. In addition, the terms of the 9.0% Notes provide that the guarantors of the prior credit facility guarantee the 9.0% Notes. As a result, upon termination of our prior credit facility and its related guaranties, the guaranties under the 9.0% Notes were cancelled and the guarantors of the 9.0% Notes were automatically released from all of their obligations under such guaranties.

Notes of Atlantic Power Corporation

On November 5, 2011, we completed a private placement of $460.0 million aggregate principal amount of 9.0% senior notes due 2018 (the "9.0% Notes") to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The

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

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6. Long-term debt (Continued)

9.0% Notes were issued at an issue price of 97.471% of the face amount of the Atlantic Notes for aggregate gross proceeds to us of $448.0 million.

On March 25, 2014, we agreed, in privately-negotiated transactions, to repurchase approximately $140.1 million aggregate principal amount of the 9.0% Notes from certain holders. We paid $15.7 million in accrued interest and premiums as part of the aggregate repurchase price, paid $0.1 million in commission fees associated with the repurchases, and wrote off $5.3 million of deferred financing costs related to the repurchase. The premiums, accrued interest and write-off of deferred financing costs were recorded to interest expense.

As previously disclosed with respect to the impact of the New Senior Secured Credit Facilities in our Current Report on Form 8-K filed on January 30, 2014, in our Annual Report on Form 10-K for the year ended December 31, 2013 and in our Quarterly Report on Form 10-Q for the three months ended March 31, 2014, due to the aggregate impact of the up-front costs resulting from the prepayments on our indebtedness described above, including the premium payment and charges for unamortized debt discount and fee expenses and premiums as part of the overall purchase price in respect of the repurchases of the 9.0% Notes (all such up-front costs, collectively, the "Prepayment Charges"), which were reflected as interest expense in our 2014 first quarter results, we no longer satisfy the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing the 9.0% Notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments. As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (approximately $61 million at June 30, 2014) until such time that we satisfy the fixed charge coverage ratio test. We have declared seven monthly dividends in January through July 2014 totaling approximately $25.6 million that were subject to the basket provision.

For the trailing twelve months ended June 30, 2014, dividend payments to our shareholders totaled approximately Cdn$48.1 million, reflecting the lower Cdn$0.03333 per common share monthly dividend first declared in March 2013. The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, any similar prepayment charges incurred in connection with any further debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

Non-Recourse 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 loans have certain financial covenants that must be met in order to distribute available cash. At June 30, 2014, all of our projects with the exception of Piedmont were in compliance with the covenants contained in project-level debt. During the first

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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6. Long-term debt (Continued)

quarter of 2014, Piedmont underwent forced maintenance outages that resulted in the project not meeting its debt service coverage ratio covenant as of June 30, 2014. We do not expect Piedmont to meet its debt service coverage ratio covenant or make distributions for at least the next twelve months.

7. 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 June 30, 2014 and December 31, 2013. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 157.6	$	$	$ 157.6
Restricted cash	35.7			35.7
Derivative instruments asset		8.0		8.0
Total	$ 193.3	$ 8.0	$	$ 201.3
Liabilities:				
Derivative instruments liability	$	$ 86.6	$	$ 86.6
Total	$	$ 86.6	$	$ 86.6

	December 31, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 158.6	$	$	$ 158.6
Restricted cash	114.2			114.2
Derivative instruments asset		13.2		13.2
Total	$ 272.8	$ 13.2	$	$ 286.0

Liabilities:								
Derivative instruments liability	$		$	104.6	$		$	104.6
Total	$		$	104.6	$		$	104.6

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature.

The fair values of our derivative instruments 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.

7. Fair value of financial instruments (Continued)

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 June 30, 2014, the credit valuation adjustments resulted in an $8.1 million net increase in fair value, which consists of a $0.5 million pre-tax gain in other comprehensive income (loss) and a $7.6 million gain in change in fair value of derivative instruments. As of December 31, 2013, the credit valuation adjustments resulted in an $11.1 million net increase in fair value, which consists of a $0.5 million pre-tax gain in other comprehensive income (loss) and a $10.6 million gain in change in fair value of derivative instruments.

8. 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 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). The guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase agreements

Gas purchase agreements at our North Bay, Kapuskasing and Nipigon projects do not qualify for the normal purchase normal sales ("NPNS") exemption and are accounted for as derivative financial instruments. The gas purchase agreements at North Bay and Kapuskasing satisfy all of the forecasted fuel requirements for these projects through their expiration on December 31, 2016. The gas purchase agreement for Nipigon satisfies the majority of forecasted fuel requirements through December 31, 2022. 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.

In June 2014, the Partnership entered into contracts for the purchase of 2.9 million Gigajoules ("Gj") of future natural gas purchases beginning on November 1, 2014 and expiring on December 31, 2017 for our projects in Ontario. These contracts effectively fix the price of approximately 98% of our expected uncontracted gas requirements for each of 2014 and 2015 and 32% and 30% of our expected uncontracted gas requirements for 2016 and 2017, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at June 30, 2014. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

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

(Unaudited)

8. Accounting for derivative instruments and hedging activities (Continued)

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.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We previously entered into natural gas swaps to effectively fix the price of 4.5 million Mmbtu of future natural gas purchases. On February 20, 2014, we paid $4.0 million to terminate a portion of these contracts in connection with the termination of our prior revolving credit facility. We recorded fuel expense related to the settlement of these contracts in the consolidated statement of operations.

We have entered into various natural gas swaps to effectively fix the price of 7.1 million Mmbtu of future natural gas purchases at Orlando, which is approximately 100% of our share of the expected on-peak natural gas purchases at the project through 2016 or approximately 89%, 62% and 63% of our share of the expected base load natural gas purchases for 2014, 2015 and 2016, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at June 30, 2014. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.0% through February 15, 2015, 6.1% from February 16, 2015 to 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).

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. Prior to conversion of the Piedmont Construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We recorded $1.0 million of deferred financing costs related to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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8. Accounting for derivative instruments and hedging activities (Continued)

this transaction in the consolidated balance sheets. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Rockland Wind Farm, LLC ("Rockland") entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the expected interest payments for the current period through December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3%-2.8%. The second tranche is for the expected interest payments for the period beginning December 31, 2026 and ending December 31, 2031, fixing the interest rate at 7.8%. The interest rate swap agreements are not designated as a hedge and changes in their fair market value are recorded in the consolidated statements of operations.

The Meadow Creek project ("Meadow Creek") has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements effectively convert 75% of the floating rate debt to a fixed interest rate of 2.3% plus an applicable margin of 2.8%-3.3% through December 31, 2024. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030, fixing the interest rate at 7.2%. The interest rate swaps were both executed on September 17, 2012 and expire on December 31, 2024 and December 31, 2030, respectively. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Epsilon Power Partners, our wholly owned subsidiary, previously had an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.37% and had a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. On February 20, 2014, we paid $2.6 million to terminate this contract in connection with the termination of our prior revolving credit facility. We recorded interest expense related to its settlement in the consolidated statement of operations. This interest rate swap agreement was not designated as a hedge and changes in its fair market value were recorded in the consolidated statements of operations.

On May 5, 2014 the Partnership entered into interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount of the $600 million aggregate principal amount of borrowings under the New Term Loan Facility. Borrowings under the $600 million New Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.75% all-in rate on the New Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $199.0 million of the New Term Loan Facility cannot be less than 4.91% if the Adjusted Eurodollar Rate is equal to or greater than 1.00%. If the Adjusted Eurodollar Rate is below 1.00%, we will pay interest at a rate equivalent to the minimum 4.75% all-in rate plus any difference between the actual Adjusted Eurodollar Rate and 1.16%.

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8. Accounting for derivative instruments and hedging activities (Continued)

The interest rate swap agreements are effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations.

Foreign currency forward contracts

From time to time, we use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars. On February 20, 2014, we paid $0.4 million to terminate all of our remaining foreign currency forward contracts in connection with the termination of our prior revolving credit facility and recorded their settlement in foreign exchange gain in the consolidated statement of operations for the three months ended March 31, 2014. On April 2, 2014, we executed a new foreign currency forward contract in which we agreed to sell $41.0 million on September 30, 2014 and receive Cdn$45.3 million at a foreign exchange rate of Cdn$1.105 per U.S. dollar in order to mitigate the foreign exchange risk on the retirement of the Cdn$44.8 million convertible debentures due in October 2014.

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 the NPNS exemption as of June 30, 2014 and December 31, 2013:

	Units	June 30, 2014	December 31, 2013
Natural gas swaps	Natural Gas (Mmbtu)	7.1	5.6
Gas purchase agreements	Natural Gas (Gj)	38.9	41.1
Interest rate swaps	Interest (US$)	152.4	161.2
Currency forwards	Cdn$	45.3	34.9

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8. Accounting for derivative instruments and hedging activities (Continued)

Fair value of derivative instruments

We have elected to 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:

	June 30, 2014	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.3
Interest rate swaps long-term		3.0
Total derivative instruments designated as cash flow hedges		4.3
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		7.8
Interest rate swaps long-term	6.3	12.6
Foreign currency forward contracts current	1.4	
Foreign currency forward contracts long-term		
Natural gas swaps current	0.3	0.2
Natural gas swaps long-term		0.7
Gas purchase agreements current		19.1
Gas purchase agreements long-term		41.9
Total derivative instruments not designated as cash flow hedges	8.0	82.3
Total derivative instruments	$ 8.0	$ 86.6

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8. Accounting for derivative instruments and hedging activities (Continued)

	December 31, 2013	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.3
Interest rate swaps long-term		2.6
Total derivative instruments designated as cash flow hedges		3.9
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		7.3
Interest rate swaps long-term	11.5	8.1
Foreign currency forward contracts current	0.5	0.7
Foreign currency forward contracts long-term	1.2	
Natural gas swaps current	0.3	1.3
Natural gas swaps long-term		3.5
Gas purchase agreements current	0.2	18.4
Gas purchase agreements long-term		61.9
Total derivative instruments not designated as cash flow hedges	13.7	101.2
Total derivative instruments	$ 13.7	$ 105.1

Accumulated other comprehensive income (loss)

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:

For the three months ended June 30, 2014	Interest Rate Swaps
Accumulated OCI balance at March 31, 2014	$ 0.1
Change in fair value of cash flow hedges	(0.3)
Realized from OCI during the period	0.1

Accumulated OCI balance at June 30, 2014	$	(0.1)

For the three months ended June 30, 2013	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2013	$ (1.2)	$ 0.1	$ (1.1)
Change in fair value of cash flow hedges	0.6		0.6
Realized from OCI during the period	0.2	(0.1)	0.1
Accumulated OCI balance at June 30, 2013	$ (0.4)	$	$ (0.4)

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

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8. Accounting for derivative instruments and hedging activities (Continued)

For the six months ended June 30, 2014	Interest Rate Swaps
Accumulated OCI balance at January 1, 2014	$ 0.2
Change in fair value of cash flow hedges	(0.7)
Realized from OCI during the period	0.4
Accumulated OCI balance at June 30, 2014	$ (0.1)

For the six months ended June 30, 2013	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at January 1, 2013	$ (1.5)	$ 0.1	$ (1.4)
Change in fair value of cash flow hedges	0.6		0.6
Realized from OCI during the period	0.5	(0.1)	0.4
Accumulated OCI balance at June 30, 2013	$ (0.4)	$	$ (0.4)

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized (gains) and losses for derivative instruments not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended June 30, 2014	Three months ended June 30, 2013
Natural gas swaps	Fuel	$ (0.2)	$
Gas purchase agreements	Fuel	13.4	14.1
Interest rate swaps	Interest, net	(3.6)	(10.8)
Foreign currency forwards	Foreign exchange loss		4.0

Six months ended June 30,

	Classification of (gain) loss recognized in income	2014	2013
Natural gas swaps	Fuel	$ 3.7	$
Gas purchase agreements	Fuel	29.3	30.4
Interest rate swaps	Interest, net	(7.8)	(13.3)
Foreign currency forwards	Foreign exchange (gain) loss	(0.1)	6.6

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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8. Accounting for derivative instruments and hedging activities (Continued)

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

	Classification of (gain) loss recognized in income	Three months ended June 30, 2014	Three months ended June 30, 2013
Natural gas swaps	Change in fair value of derivatives	$ 1.0	$ 1.1
Gas purchase agreements	Change in fair value of derivatives	(2.6)	(7.4)
Interest rate swaps	Change in fair value of derivatives	4.4	(18.0)
Total change in fair value of derivative instruments		$ 2.8	$ (24.3)
Foreign currency forwards	Foreign exchange (gain) loss	$ (1.4)	$ 12.8

	Classification of (gain) loss recognized in income	Six months ended June 30, 2014	Six months ended June 30, 2013
Natural gas swaps	Change in fair value of derivatives	$ (3.5)	$ 0.7
Gas purchase agreements	Change in fair value of derivatives	(18.6)	(15.5)
Interest rate swaps	Change in fair value of derivatives	10.2	(22.1)
Total change in fair value of derivative instruments		$ (11.9)	$ (36.9)
Foreign currency forwards	Foreign exchange (gain) loss	$ (0.3)	$ 18.8

9. Income taxes

	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Current income tax expense	$ 1.4	$ 3.4	$ 2.6	$ 5.4
Deferred tax benefit	(2.0)	(2.8)	(15.5)	(7.3)

Total income tax (benefit), net	$ (0.6)	$ 0.6	$ (12.9)	$ (1.9)

Income tax benefit for the three months ended June 30, 2014 was $0.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $14.8 million. The primary items impacting the tax rate for the three months ended June 30, 2014 were $14.2 million relating to a change in the valuation allowance, $2.4 million relating to foreign exchange, and $1.1 million of other permanent differences. These items were partially offset by $3.5 million relating to operating in higher tax rate jurisdictions.

Income tax benefit for the six months ended June 30, 2014 was $12.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $23.8 million. The primary items impacting the tax rate for the six months ended June 30, 2014 were $29.3 million

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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9. Income taxes (Continued)

relating to a change in the valuation allowance, $2.6 million relating to minority interest adjustments, and $0.5 million of other permanent differences. These items were partially offset by $11.1 million of capital losses recognized on tax restructuring, $9.2 million relating to operating in higher tax rate jurisdictions, and $1.2 million relating to foreign exchange.

As of June 30, 2014, we have recorded a valuation allowance of $157.4 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 United States and in Canada and available tax planning strategies.

10. Equity compensation plans

Long-Term Incentive Program

The following table summarizes the changes in LTIP notional units during the three months ended June 30, 2014:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2013	766,988	$ 7.86
Granted	1,776,083	2.64
Reinvested	99,452	4.12
Forfeited	(182,783)	8.00
Vested	(242,160)	8.72
Outstanding at June 30, 2014	2,217,580	$ 3.41

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies and, in some cases, Project Adjusted EBITDA per common share compared to budget. Compensation expense for notional units granted in 2014 is recorded net of estimated forfeitures. See Note 16 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2013 for further details. Cash payments made for vested notional units for the six months ended June 30, 2014 and 2013 was $0.2 million and $0.9 million, respectively. Compensation expense for LTIP was $1.0 million and $0.9 million for the three and six months ended June 30, 2014, respectively and $0.8 million and $1.2 million for the three and six months ended June 30, 2013, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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11. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2013. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP. The following table sets forth the diluted net income (loss) and potentially dilutive shares utilized in the per share calculation for the three and six months ended June 30, 2014 and 2013:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Numerator:				
(Loss) income from continuing operations attributable to Atlantic Power Corporation	$ (59.2)	$ 2.4	$ (77.9)	$ 8.4
Loss from discontinued operations, net of tax		(5.4)	(0.1)	(4.9)
Net (loss) income attributable to Atlantic Power Corporation	$ (59.2)	$ (3.0)	$ (78.0)	$ 3.5
Denominator:				
Weighted average basic shares outstanding	120.6	119.9	120.5	119.7
Dilutive potential shares:				
Convertible debentures	27.7	27.7	27.7	27.7
LTIP notional units	0.4	0.8	0.2	0.6
Potentially dilutive shares	148.7	148.4	148.4	148.0
Diluted (loss) earnings per share from continuing operations attributable to Atlantic Power Corporation	$ (0.49)	$ 0.02	$ (0.65)	$ 0.07
Diluted loss per share from discontinued operations		(0.05)		(0.04)
Diluted (loss) income per share attributable to Atlantic Power Corporation	$ (0.49)	$ (0.03)	$ (0.65)	$ 0.03

Potentially dilutive shares from convertible debentures and LTIP notional units have been excluded from fully diluted shares for the three and six months ended June 30, 2014 and 2013 because their impact would be anti-dilutive.

12. Discontinued operations

On March 6, 2014, we sold our outstanding membership interests in Greeley for approximately $1.0 million and recorded a $2.1 million non-cash gain on the sale related to the write-off of asset retirement obligations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2014 and 2013, respectively.

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12. Discontinued operations (Continued)

On November 5, 2013, we completed the sale of our 60% interest in Rollcast to its remaining shareholders. As consideration for the sale, we were assigned asset management contracts valued at $0.5 million for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million in cash to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013.

The Florida Projects and Path 15 were sold on April 12, 2013 and April 30, 2013, respectively. Accordingly, the projects' net income (loss) is recorded as income (loss) from discontinued operations, net of tax in the statements of operations for the three and six months ended June 30, 2013.

The following tables summarize the revenue, income (loss) from operations, and income tax expense of Greeley, Rollcast, Path 15 and the Florida Projects for the three and six months ended June 30, 2014 and 2013:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Revenue	$	$ 11.4	$	$ 77.2
(Loss) income from operations of discontinued businesses		(5.0)	(0.1)	(4.1)
Income tax expense		0.4		0.8
(Loss) income from operations of discontinued businesses, net of tax	$	$ (5.4)	$ (0.1)	$ (4.9)

Basic and diluted earnings (loss) per share related to income (loss) from discontinued operations for Greeley, Rollcast, the Florida Projects and Path 15 was $0.00 and $(0.05) for the three months ended June 30, 2014 and 2013, respectively, and $0.00 and $0.04 for the six months ended June 30, 2014 and 2013, respectively.

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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, noncontrolling interests and total equity for the six months ended June 30, 2014 and 2013:

	Six months ended June 30, 2014			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 608.3	$ 221.3	$ 266.4	$ 1,096.0
Net (loss) income	(78.0)	5.9	(6.7)	(78.8)
Realized and unrealized gain on hedging activities, net of tax	(0.2)			(0.2)
Foreign currency translation adjustment, net of tax	(1.5)			(1.5)
Common shares issued for LTIP	0.6			0.6
Dividends paid to noncontrolling interest			(5.2)	(5.2)
Dividends declared on common shares	(21.1)			(21.1)
Dividends declared on preferred shares of a subsidiary company		(5.9)		(5.9)
Balance at June 30	$ 508.1	$ 221.3	$ 254.5	$ 983.9

	Six months ended June 30, 2013			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 729.7	$ 221.3	$ 235.4	$ 1,186.4
Net income (loss)	3.5	6.3	(0.8)	9.0
Realized and unrealized gain on hedging activities, net of tax	1.0			1.0
Foreign currency translation adjustment, net of tax	(30.1)			(30.1)
Common shares issued for LTIP	0.9			0.9
Contribution by and sale of noncontrolling interest			44.5	44.5
Costs associated with tax equity raise	(0.9)			(0.9)
Dividends paid to noncontrolling interest			(2.9)	(2.9)
Dividends declared on common shares	(35.5)			(35.5)
Dividends declared on preferred shares of a subsidiary company		(6.3)		(6.3)

Balance at June 30	$ 668.6	$ 221.3	$ 276.2	$ 1,166.1

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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14. Segment and geographic information

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the three and six months ended June 30, 2014 and 2013 have been presented to reflect these changes in operating segments. 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. 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 use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Greeley and Path 15, which are components of the West segment, the Florida Projects, components of the East segment, and Rollcast, which is a component of Un-allocated Corporate, are included in the income (loss) from discontinued operations line item in the table below. We have adjusted prior periods to reflect this reclassification. A reconciliation of project income (loss) to Project Adjusted EBITDA is included in the table below:

	East	West	Wind	Un-allocated Corporate	Consolidated
Three months ended June 30, 2014					
Project revenues	$ 76.2	$ 46.8	$ 20.0	$ 0.2	$ 143.2
Segment assets	1,192.3	977.6	818.1	222.7	3,210.7
Project Adjusted EBITDA	$ 38.5	$ 22.9	$ 17.2	$ (3.6)	$ 75.0
Change in fair value of derivative instruments	(0.8)		2.8	1.1	3.1
Depreciation and amortization	24.4	16.2	11.5	0.2	52.3
Interest, net	3.7		4.8	0.1	8.6
Other project expense	14.8				14.8
Project income (loss)	(3.6)	6.7	(1.9)	(5.0)	(3.8)
Administration				10.2	10.2
Interest, net				27.7	27.7
Foreign exchange (loss) gain				15.3	15.3
Other income, net					
Income (loss) from continuing operations before income taxes	(3.6)	6.7	(1.9)	(58.2)	(57.0)
Income tax benefit				(0.6)	(0.6)
Net income (loss)	$ (3.6)	$ 6.7	$ (1.9)	$ (57.6)	$ (56.4)

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14. Segment and geographic information (Continued)

	East	West	Wind	Un-allocated Corporate	Consolidated
Three months ended June 30, 2013					
Project revenues	$ 71.9	$ 45.8	$ 18.2	$ 0.2	$ 136.1
Segment assets	1,468.7	1,056.0	907.4	135.3	3,567.4
Project Adjusted EBITDA	$ 29.4	$ 14.1	$ 15.5	$ (3.1)	$ 55.9
Change in fair value of derivative instruments	(10.6)		(15.3)	(0.9)	(26.8)
Depreciation and amortization	21.8	17.1	11.4	0.2	50.5
Interest, net	5.5	0.1	4.9	(1.0)	9.5
Other project expense	0.5			1.9	2.4
Project income (loss)	12.2	(3.1)	14.5	(3.3)	20.3
Administration				11.8	11.8
Interest, net				25.3	25.3
Foreign exchange gain				(14.5)	(14.5)
Other income, net				(9.5)	(9.5)
Income (loss) from continuing operations before income taxes	12.2	(3.1)	14.5	(16.4)	7.2
Income tax expense				0.6	0.6
Net income (loss) from continuing operations	12.2	(3.1)	14.5	(17.0)	6.6
Loss from discontinued operations	(1.2)	1.2		(5.4)	(5.4)
Net income (loss)	$ 11.0	$ (1.9)	$ 14.5	$ (22.4)	$ 1.2

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

14. Segment and geographic information (Continued)

	East	West	Wind	Un-allocated Corporate	Consolidated
Six months ended June 30, 2014					
Project revenues	$ 162.8	$ 85.3	$ 40.1	$ 0.3	$ 288.5
Segment assets	1,192.3	977.6	818.1	222.7	3,210.7
Project Adjusted EBITDA	$ 84.0	$ 34.1	$ 35.1	$ (3.6)	$ 149.6
Change in fair value of derivative instruments	(22.6)		10.4	1.2	(11.0)
Depreciation and amortization	48.8	32.6	22.8	0.5	104.7
Interest, net	15.3		9.4		24.7
Other project expense	14.8				14.8
Project income (loss)	27.7	1.5	(7.5)	(5.3)	16.4
Administration				17.5	17.5
Interest, net				94.1	94.1
Foreign exchange (loss) gain				(1.5)	(1.5)
Other income, net				(2.1)	(2.1)
Income (loss) from continuing operations before income taxes	27.7	1.5	(7.5)	(113.3)	(91.6)
Income tax benefit				(12.9)	(12.9)
Net income (loss) from continuing operations	27.7	1.5	(7.5)	(100.4)	(78.7)
Loss from discontinued operations		(0.1)			(0.1)
Net income (loss)	$ 27.7	$ 1.4	$ (7.5)	$ (100.4)	$ (78.8)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

14. Segment and geographic information (Continued)

	East	West	Wind	Un-allocated Corporate	Consolidated
Six months ended June 30, 2013					
Project revenues	$ 151.7	$ 86.4	$ 35.7	$ (0.2)	$ 273.6
Segment assets	1,468.7	1,056.0	907.4	135.3	3,567.4
Project Adjusted EBITDA	$ 78.5	$ 34.7	$ 30.5	$ (7.6)	$ 136.1
Change in fair value of derivative instruments	(20.0)		(18.3)		(38.3)
Depreciation and amortization	44.2	34.2	23.7	0.2	102.3
Interest, net	9.9	0.1	9.8	(0.1)	19.7
Other project expense	1.0			(0.4)	0.6
Project income (loss)	43.4	0.4	15.3	(7.3)	51.8
Administration				20.1	20.1
Interest, net				51.2	51.2
Foreign exchange gain				(22.0)	(22.0)
Other income, net				(9.5)	(9.5)
Income (loss) from continuing operations before income taxes	43.4	0.4	15.3	(47.1)	12.0
Income tax benefit				(1.9)	(1.9)
Net income (loss) from continuing operations	43.4	0.4	15.3	(45.2)	13.9
Loss from discontinued operations	(0.9)	1.8		(5.8)	(4.9)
Net income (loss)	$ 42.5	$ 2.2	$ 15.3	$ (51.0)	$ 9.0

The table below provides information, by country, about our consolidated operations for the three and six months ended June 30, 2014 and 2013 and Property, Plant & Equipment as of June 30, 2014 and December 31, 2013, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Project Revenue Three months ended June 30,		Project Revenue Six months ended June 30,		Property, Plant and Equipment, net of accumulated depreciation	
	2014	2013	2014	2013	June 30, 2014	December 31, 2013
United States	$ 98.2	$ 91.0	$ 191.3	$ 161.1	$ 1,296.6	$ 1,330.5
Canada	45.0	45.1	97.2	112.5	454.6	482.9

Total	$	143.2	$	136.1	$	288.5	$	273.6	$	1,751.2	$	1,813.4

Ontario Electricity Financial Corp ("OEFC"), San Diego Gas & Electric, and BC Hydro provided 21.9%, 16.7%, and 9.6%, respectively, of total consolidated revenues for the three months ended June 30, 2014 and 25.0%, 15.0%, and 8.7%, respectively, of total consolidated revenues for the six months ended June 30, 2014. OEFC, San Diego Gas & Electric and BC Hydro provided 22.6%, 15.9%, and 10.3%, respectively, of total consolidated revenues for the three months ended June 30, 2013 and

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

14. Segment and geographic information (Continued)

29.7%, 13.7%, and 11.3%, respectively, of total consolidated revenues for the six months ended June 30, 2013. OEFC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the East segment. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West segment. BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the West segment.

15. 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.

In connection with the tax equity investments in our Canadian Hills project, we have expressly indemnified the investors for certain representations and warranties made by a wholly-owned subsidiary with respect to matters which we believe are remote. The expiration dates of these guarantees vary from less than one year through the indefinite termination date of the project. Our maximum undiscounted potential exposure is limited to the amount of tax equity investment less cash distributions made to the investors and any amount equal to the net federal income tax benefits arising from production tax credits.

16. Contingencies

Shareholder class action lawsuits

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our President and Chief Executive Officer and a Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Proposed Individual Defendants," and together with Atlantic Power, the "Proposed Defendants") (the "U.S. Actions").

The District Court complaints differed in terms of the identities of the Proposed Individual Defendants they named, as noted above, the named plaintiffs, and the purported class period they alleged (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleged, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Proposed Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

16. Contingencies (Continued)

dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Proposed Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Proposed Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that the Proposed Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013.

On March 31, 2014, the Court entered an order consolidating the five individual U.S. Actions, appointing the Feldman, Shapero, Carter and Smith investor group (one of the six U.S. Lead Plaintiffs Applicants) as Lead Plaintiff and approving Lead Plaintiff's selection of counsel. The Court also granted the parties' joint motion regarding initial case scheduling and directed the parties to resubmit a proposed schedule that contains specific dates. In response to that directive, on April 7, 2014, Lead Plaintiff filed an application and proposed order, which sought an extension of the schedule contained in the joint motion. The application and proposed order requested that: (i) Lead Plaintiff be permitted to file an amended complaint on or before May 30, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before July 29, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before September 24, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 13, 2014. Proposed Defendants did not object to the schedule proposed by Lead Plaintiff. On May 29, 2014, Lead Plaintiff filed a renewed application and proposed order, which sought another extension of the schedule, and on June 3, 2014, Lead Plaintiff and the Proposed Defendants jointly filed a stipulation and proposed order requesting the following revised schedule: (i) Lead Plaintiff be permitted to file an amended complaint on or before June 6, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before August 5, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before October 6, 2014, and

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

16. Contingencies (Continued)

(iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 20, 2014. On June 3, 2014, the Court entered an order setting this requested schedule.

On June 6, 2014, Lead Plaintiff filed the amended complaint (the "Amended Complaint"). The Amended Complaint names as defendants Barry E. Welch and Terrence Ronan (the "Individual Defendants") and Atlantic Power (together with the Individual Defendants, the "Defendants") and alleges a class period of June 20, 2011 to March 4, 2013 (the "Class Period"). The Amended Complaint makes allegations that are substantially similar to those asserted in the five initial complaints. Specifically, the Amended Complaint alleges, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend, which artificially inflated the price of Atlantic Power's common shares during the class period. The Amended Complaint continues to assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. It also asserts a claim for unjust enrichment against the Individual Defendants. In accordance with the schedule referenced above, Defendants filed their motion to dismiss the consolidated U.S. Action on August 5, 2014.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. As in the U.S. Action, this claim names the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs seeks leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(Unaudited)

16. Contingencies (Continued)

claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

The Defendants are preparing materials to contest leave and certification.

A schedule for the Plaintiffs' motions and the action is set that contemplates a hearing on leave and certification during the week of March 30, 2015.

The proposed class action in Quebec is stayed until March 30, 2015 to follow the action in Ontario.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously against each of the actions.

IRS Examination

In 2011, the Internal Revenue Service ("IRS") began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous Income Participating Security structure to our current traditional common share structure. At June 30, 2014, the examination is before the IRS Office of Appeals.

We continue to vigorously contest these proposed adjustments, including pursuing all administrative and judicial remedies available to us. We expect to be successful in sustaining our positions with no material impact to our financial results. We believe an adjustment, if any, would be offset by net operating loss carry forwards. No accrual has been made for any contingency related to any of the proposed adjustments as of June 30, 2014.

Other

In addition to the other matters listed, from time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of June 30, 2014.

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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," "believe," "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 pay dividends, service our debt obligations or finance internal or external growth opportunities;
- our ability to evaluate and/or implement a broad range of potential strategic options and the impact any such potential options may have on us or our stock price;
- our ability to meet the financial covenants under our New Senior Secured Credit Facilities 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, 2013. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- our ability to generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities;
- the ability to evaluate and/or implement a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, the dividend level, as well as broader strategic options, including a sale or merger of the Company, and the impact any such potential options may have on us or our stock price;
- the impact of our failure to meet the fixed charge coverage ratio test in the restricted payments covenants of the indenture governing our 9.0% senior unsecured notes;

our indebtedness and financing arrangements and the terms, covenants and restrictions included in our New Senior Secured Credit Facilities;

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;

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- unstable capital and credit markets;
- the outcome of certain shareholder class action lawsuits;
- the expiration or termination of power purchase agreements and our ability to renew or enter into new power purchase agreements on favorable terms or at all;
- 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;
- the dependence of our wind power projects on suitable wind and associated conditions and of our hydropower projects on suitable precipitation and associated weather 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 coverages;
- the impact of significant energy, environmental and other regulations on our projects;
- the impact of impairment of goodwill or long-lived assets;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority-owned projects;
- transfer restrictions on our equity interests in certain projects;

- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and
- our ability to retain, motivate and recruit executives and other key employees.

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

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

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

OVERVIEW

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of June 30, 2014, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,945 megawatts ("MW") in which our aggregate ownership interest is approximately 2,024 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") which we sold in a transaction that closed in July 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer based in Seattle, Washington. Twenty of our projects are majority-owned subsidiaries.

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from August 31, 2014 (at Selkirk) to December 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.

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

We directly operate and maintain twenty-one of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Colorado Energy Management ("CEM") and Power Plant Management Services ("PPMS"). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

As previously disclosed, we continue to focus on how to best position the Company to maximize value for its shareholders. In that framework, we are considering the relative merits of additional debt reduction, investment in accretive growth opportunities (both internal and external), and other allocation of available cash. Consistent with the objective of acting in the best interests of the Company, its shareholders and its other stakeholders, we, as also previously disclosed, are committed to evaluating a broad range of potential options. These potential options include further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options, including a sale or merger of the Company. As previously disclosed, we have engaged Goldman, Sachs & Co. and Greenhill & Co., LLC to assist us in the evaluation of these potential options. No assurance can be given as to how the evaluation of any such potential options may evolve.

RECENT DEVELOPMENTS

Sale of Delta-Person

In December 2012 we and the other owners of Delta-Person, entered into a purchase and sale agreement with BHB Power, LLC and Public Service Company of New Mexico to sell the project for approximately $37.2 million including working capital adjustments. The sale closed in July 2014 and we received net cash proceeds for our ownership interest of approximately $7.2 million in the aggregate. We expect to receive an additional $1.4 million of cash proceeds held in escrow for up to twelve months after the close of the transaction. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Delta-Person is expected to result in a gain on sale of approximately $8.6 million that will be recorded as a component of other income in the consolidated statement of operations for the three months ended September 30, 2014.

Tunis Long-Lived Asset and Goodwill Impairment

Under our accounting policies for long-lived assets and goodwill impairment, we perform an impairment analysis at the earlier of (i) executing a new PPA (or other arrangement) and (ii) six months prior to the expiration of an existing PPA. The Tunis project's PPA expires on December 31, 2014 and accordingly, we performed a long-lived assets impairment test and a goodwill impairment test as of June 30, 2014. Based on the results of these tests, the project recorded a $9.6 million long-lived impairment charge and a $5.2 million goodwill impairment charge in the three months ended June 30, 2014. The $14.8 million aggregate long-lived asset and goodwill impairment was primarily due to our assessment of the forecasted cash flows from re-contracting and other strategic outcomes at Tunis.

In addition to our review of Tunis and based on the continued deficit of our market capitalization as compared to our book carrying value, we determined that it was appropriate to initiate a test of the remaining goodwill at our reporting units to determine if it is more likely than not that the fair value of our reporting units do not exceed their carrying amounts. As of the date of this Quarterly Report on Form 10-Q, we are currently gathering the necessary information to perform these tests and expect to complete them during the three months ended September 30, 2014.

Sale of Greeley

In March 2014, we closed a transaction with Initium Power Partners, LLC. ("Initium"), whereby Initium agreed to purchase all of the issued and outstanding membership interests in Greeley for approximately $1.0 million. We recorded a $2.1 million non-cash gain on the sale in the statement of operations. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the six months ended June 30, 2014.

New Senior Secured Credit Facilities

On February 24, 2014, Atlantic Power Limited Partnership (the "Partnership"), our wholly-owned indirect subsidiary, entered into a new senior secured term loan facility (the "New Term Loan Facility"), comprising $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "New Revolving Credit Facility') with a capacity of $210 million (collectively, the "New Senior Secured Credit Facilities"). On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and at letters of credit in an aggregate face amount of $144.1 million ($107.6 million as of August 7, 2014) were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used to (i) fund a debt service reserve in an amount equivalent to six months of debt service (approximately $15.8 million) and (ii) support

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contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility to:

- redeem in whole, at a price equal to par plus $31.1 million of accrued interest and make-whole premiums (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 (the "Series A Notes") and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 (the "Series B Notes") issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses of approximately $40.0 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and

- make a distribution to us in the amount of $122 million which was used, in addition to cash on hand, to repurchase $140.1 million aggregate principal amount of Atlantic Power Corporation's 9.0% senior unsecured notes due October 2018 (the "9.0% Notes"), make $15.7 million in accrued interest and premium payments as part of the aggregate repurchase price, and $0.1 million in commission fees associated with the repurchases. Having substantially completed our previously announced intention to repurchase or redeem up to $150 million aggregate principal amount of the 9.0% Notes, we do not expect at this time to repurchase or redeem any additional amounts of the 9.0% Notes, but reserve the right to do so in the future.

The foregoing description of the New Senior Secured Credit Facilities is qualified in its entirety by reference to the full text of the credit agreement governing the New Senior Secured Credit Facilities, which is filed as Exhibit 10.1 to our Annual Report on Form 10-K for the year ended December 31, 2013. For a further description of the New Senior Secured Credit Facilities and use of proceeds therefrom, see " Liquidity and Capital Resources" and Note 11 to the consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2013.

OUR POWER PROJECTS

The table on the following page outlines our portfolio of power generating assets in operation as of August 7, 2014, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. Our customers are generally large utilities and other parties with investment-grade credit ratings, as measured by Standard & Poor's ("S&P"). For customers rated by Moody's, we substitute the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment-grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment-grade have weaker capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

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Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
East Segment								
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	December 2028	BBB
Chambers(1)	New Jersey	Coal	262	40.00%	89	Atlantic City Elec.(2)	March 2024	BBB+
					16	DuPont	March 2024	A
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Merck, & Co., Inc.	September 2018	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	December 2027(3)	A-
Selkirk(1)(4)	New York	Natural Gas	345	18.50%	15	Merchant	N/A	N/R
					49	Consolidated Edison	August 2014	A-
Calstock	Ontario	Biomass	35	100.00%	35	Ontario Electricity Financial Corp	June 2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-
Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2022	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	December 2017	AA-
Tunis(4)	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	December 2014	AA-
Orlando(1)	Florida	Natural Gas	129	50.00%	65	Progress Energy Florida	December 2023	BBB+

Piedmont	Georgia	Biomass	53	100.0%	53	Georgia Power	December 2032	A
Morris	Illinois	Natural Gas	177	100.00%	100	Merchant	N/A	N/A
					77	Equistar Chemicals, LP[5]	November 2023	BBB+
West Segment								
Mamquam	British Columbia	Hydro	50	100.00%	50	British Columbia Hydro and Power Authority	September 2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00%	6	British Columbia Hydro and Power Authority	August 2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00%	66	British Columbia Hydro and Power Authority	March 2018	AAA
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	December 2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	December 2019	A
North Island	California	Natural Gas	42	100.00%	42	San Diego Gas & Electric	December 2019	A
Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	May 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00%	300	Public Service Company of Colorado	April 2022	A-
Frederickson[1]	Washington	Natural Gas	250	50.15%	50	Benton Co. PUD	August 2022	A+
					45	Grays Harbor PUD	August 2022	A
					30	Franklin, Co. PUD	August 2022	A
Koma Kulshan[1]	Washington	Hydro	13	49.80%	6	Puget Sound Energy		BBB

							December 2037	
Wind Segment								
Idaho Wind[1]	Idaho	Wind	183	27.56%	49	Idaho Power Co.	December 2030	BBB
Rockland	Idaho	Wind	80	50.00%	40	Idaho Power Co.	December 2036	BBB
Goshen North[1]	Idaho	Wind	125	12.50%	16	Southern California Edison	November 2030	BBB+
Meadow Creek	Idaho	Wind	120	100.00%	120	PacifiCorp	December 2032	A-
Canadian Hills	Oklahoma	Wind	298	99.0%	199	Southwestern Electric Power Company	December 2032	BBB
					48	Oklahoma Municipal Power Authority	December 2037	A
					48	Grand River Dam Authority	December 2032	A

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

(2) 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.

(3) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through June 30, 2014, the facility has generated 6,270 GWh under its PPA.

(4) We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements. No assurance can be provided that we will be able to renew or enter into new power purchase agreements on favorable terms or at all. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition" in our Annual Report on Form 10-K for the year ended December 31, 2013.

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

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Consolidated Overview and Results of Operations

Performance highlights

The following table provides a summary of our consolidated results of operations for the three and six months ended June 30, 2014 and 2013 which are analyzed in greater detail below:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	2014	2013
Project (loss) income	$ (3.8)	$ 20.3	$ 16.4	$ 51.8
(Loss) income from continuing operations	$ (56.4)	$ 6.6	$ (78.7)	$ 13.9
Loss from discontinued operations	$	$ (5.4)	$ (0.1)	$ (4.9)
Net (loss) income attributable to Atlantic Power Corporation	$ (59.2)	$ (3.0)	$ (78.0)	$ 3.5
(Loss) income per share from continuing operations attributable to Atlantic Power Corporation basic and diluted	$ (0.49)	$ 0.02	$ (0.65)	$ 0.07
Loss per share from discontinued operations basic		(0.05)		(0.04)
(Loss) income per share attributable to Atlantic Power Corporation basic and diluted	$ (0.49)	$ (0.03)	$ (0.65)	$ 0.03
Project Adjusted EBITDA[1]	$ 75.0	$ 55.9	$ 149.6	$ 136.1
Free Cash Flow[1]	$ (15.1)	$ (7.5)	$ (61.0)	$ 74.5

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

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as a result of significant project asset sales and in order to align our reportable business segments with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the three and six months ended June 30, 2014 and 2013 have been presented to reflect these changes in operating segments. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

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Three months ended June 30, 2014 compared to the three months ended June 30, 2013

The following table provides our consolidated results of operations:

	Three months ended June 30,			
	2014	2013	$ change	% change
Project revenue:				
Energy sales	$ 82.4	$ 76.9	$ 5.5	7%
Energy capacity revenue	41.3	42.9	(1.6)	-4%
Other	19.5	16.3	3.2	20%
	143.2	136.1	7.1	5%
Project expenses:				
Fuel	50.4	50.0	0.4	1%
Operations and maintenance	34.5	46.4	(11.9)	-26%
Development	1.1	1.8	(0.7)	-39%
Depreciation and amortization	40.9	41.8	(0.9)	-2%
	126.9	140.0	(13.1)	-9%
Project other income (expense):				
Change in fair value of derivative instruments	(2.8)	24.3	(27.1)	-112%
Equity in earnings of unconsolidated affiliates	3.3	8.7	(5.4)	-62%
Interest expense, net	(5.8)	(8.8)	3.0	-34%
Impairment	(14.8)		(14.8)	NM
	(20.1)	24.2	(44.3)	NM
Project (loss) income	(3.8)	20.3	(24.1)	-119%
Administrative and other expenses (income):				
Administration	10.2	11.8	(1.6)	-14%
Interest, net	27.7	25.3	2.4	9%
Foreign exchange loss (gain)	15.3	(14.5)	29.8	NM
Other income, net		(9.5)	9.5	NM
	53.2	13.1	40.1	NM
(Loss) income from continuing operations before income taxes	(57.0)	7.2	(64.2)	NM
Income tax (benefit) expense	(0.6)	0.6	(1.2)	NM
(Loss) income from continuing operations	(56.4)	6.6	(63.0)	NM
Loss from discontinued operations, net of tax		(5.4)	5.4	NM
Net (loss) income	(56.4)	1.2	(57.6)	NM
Net (loss) income attributable to noncontrolling interests	(0.3)	1.1	(1.4)	NM
Net income attributable to Preferred share dividends of a subsidiary company	3.1	3.1		NM

Net (loss) income attributable to Atlantic Power Corporation	$	(59.2)	(3.0)	(56.2)	NM

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Project Income (loss) by Segment

	Three months ended June 30, 2014				
	East	West[(1)]	Wind	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 38.8	$ 23.6	$ 20.0	$	$ 82.4
Energy capacity revenue	28.2	13.1			41.3
Other	9.2	10.1		0.2	19.5
	76.2	46.8	20.0	0.2	143.2
Project expenses:					
Fuel	35.8	14.6			50.4
Operations and maintenance	13.5	12.9	5.4	2.7	34.5
Development				1.1	1.1
Depreciation and amortization	17.3	13.4	10.1	0.1	40.9
	66.6	40.9	15.5	3.9	126.9
Project other income (expense):					
Change in fair value of derivative instruments	0.9		(2.4)	(1.3)	(2.8)
Equity in earnings of unconsolidated affiliates	2.9	0.8	(0.4)		3.3
Interest expense, net	(2.2)		(3.6)		(5.8)
Impairment	(14.8)				(14.8)
	(13.2)	0.8	(6.4)	(1.3)	(20.1)
Project income (loss)	$ (3.6)	$ 6.7	$ (1.9)	$ (5.0)	$ (3.8)

(1) Excludes Greeley which is designated as discontinued operations.

	Three months ended June 30, 2013				
	East[(1)]	West[(2)]	Wind	Un-allocated Corporate[(3)]	Consolidated Total
Project revenue:					
Energy sales	$ 36.1	$ 22.1	$ 18.2	$ 0.5	$ 76.9
Energy capacity revenue	29.9	13.2		(0.2)	42.9
Other	5.9	10.5		(0.1)	16.3
	71.9	45.8	18.2	0.2	136.1
Project expenses:					
Fuel	35.5	14.4		0.1	50.0
Operations and maintenance	18.1	21.7	5.1	1.5	46.4
Development				1.8	1.8

Depreciation and amortization		17.6		13.6		10.2		0.4		41.8
		71.2		49.7		15.3		3.8		140.0
Project other income (expense):										
Change in fair value of derivative instruments		10.2				14.1				24.3
Equity in earnings of unconsolidated affiliates		6.5		0.8		1.1		0.3		8.7
Interest expense, net		(5.2)				(3.6)				(8.8)
Impairment										
		11.5		0.8		11.6		0.3		24.2
Project income (loss)	$	12.2	$	(3.1)	$	14.5	$	(3.3)	$	20.3

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Path 15 and Greeley which are designated as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations.

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East

Project income for 2014 decreased $15.8 million from the comparable 2013 period primarily due to:

- decreased project income of $12.6 million at Tunis due primarily to a $14.8 million long-lived asset and goodwill impairment partially offset by decreased maintenance costs from the comparable 2013 period;
- decreased project income of $4.9 million at Selkirk in equity earnings due primarily to accelerated depreciation resulting from the upcoming expiration of the project's PPA in August 2014;
- decreased project income of $4.0 million at Nipigon due primarily to a negative $4.5 million non-cash change in the fair value of a gas purchase agreement that were accounted for as derivatives; and
- decreased project income of $2.8 million at Piedmont due primarily to a negative $4.6 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives.

These decreases were partially offset by:

- increased project income of $3.4 million at Curtis Palmer due primarily to a $2.8 million decrease in interest expense resulting from the redemption of the project's 5.9% Senior Notes due 2014 in the first quarter of 2014;
- increased project income of $3.3 million at Orlando due primarily to lower fuel costs than in the comparable 2013 period; and
- increased project income of $2.1 million at Kapuskasing which had decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul.

West

Project income for 2014 increased $9.8 million from the comparable 2013 period primarily due to:

- increased project income of $3.7 million at Naval Training Center due primarily to decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul;
- increased project income of $3.4 million at Williams Lake due primarily to decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul; and
- increased project income of $2.3 million at Mamquam due primarily to decreased maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled turbine and generator overhaul.

Wind

Project income for 2014 decreased $16.4 million from the comparable 2013 period primarily due to:

decreased project income from Meadow Creek of $7.7 million due primarily to a negative $8.9 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives; and

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decreased project income from Rockland of $7.3 million due primarily to a negative $7.6 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives.

Un-allocated Corporate

Total project loss did not change materially from the comparable 2013 period.

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 comparable 2013 period.

Interest, net

Interest expense increased $2.4 million or 9% from the comparable 2013 period primarily due to (i) a $7.1 million in interest on the term loan facility of the Partnership, (ii) a $1.2 million increase in amortization of deferred finance costs related to the term loan facility and (iii) a $0.9 million increase in expense for issued letters of credit. This was partially offset by (i) a $3.2 million decrease in interest expense due to the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014 and (ii) a $3.3 million decrease in interest expense due to the redemption of the Series A Notes and the Series B Notes in the first quarter of 2014.

Foreign exchange loss (gain)

Foreign exchange loss increased $29.8 million from the comparable 2013 period primarily due to a $33.1 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars, a $10.8 million realized gain on the settlement of foreign currency forward contracts in the comparable 2013 period, offset by a $14.1 million decrease in unrealized loss on foreign exchange forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.07 and 1.05 at June 30, 2014 and 2013, respectively, a decrease of 3.5% in the three months ended June 30, 2014 compared to an increase of 3.5% in the three months ended June 30, 2013.

Other income, net

Other income, net decreased $9.5 million from the 2013 comparable period primarily due to a $10.3 million gain and management fee agreement termination fee resulting from the sale of Path 15 in the second quarter of 2013.

Income tax benefit

Income tax benefit for the three months ended June 30, 2014 was $0.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was

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$14.8 million. The primary items impacting the tax rate for the three months ended June 30, 2014 were $14.2 million relating to a change in the valuation allowance, $2.4 million relating to foreign exchange, and $1.1 million of other permanent differences. These items were partially offset by $3.5 million relating to operating in higher tax rate jurisdictions.

Income tax expense from continuing operations for the three months ended June 30, 2013 was $0.6 million, which is consistent with the expected income tax expense based on the Canadian enacted statutory rate of 25%.

Six months ended June 30, 2014 compared to the six months ended June 30, 2013

The following table provides our consolidated results of operations:

	Six months ended June 30,			
	2014	**2013**	**$ change**	**% change**
Project revenue:				
Energy sales	$ 164.7	$ 153.8	$ 10.9	7%
Energy capacity revenue	74.8	77.2	(2.4)	-3%
Other	49.0	42.6	6.4	15%
	288.5	273.6	14.9	5%
Project expenses:				
Fuel	110.2	97.7	12.5	13%
Operations and maintenance	67.2	73.9	(6.7)	-9%
Development	1.8	3.5	(1.7)	-49%
Depreciation and amortization	81.5	82.7	(1.2)	-1%
	260.7	257.8	2.9	1%
Project other income (expense):				
Change in fair value of derivative instruments	11.9	36.9	(25.0)	-68%
Equity in earnings of unconsolidated affiliates	11.9	15.9	(4.0)	-25%
Interest expense, net	(20.4)	(16.8)	(3.6)	21%
Impairment	(14.8)		(14.8)	NM
	(11.4)	36.0	(47.4)	NM
Project income	16.4	51.8	(35.4)	-68%
Administrative and other expenses (income):				
Administration	17.5	20.1	(2.6)	-13%
Interest, net	94.1	51.2	42.9	84%
Foreign exchange (gain) loss	(1.5)	(22.0)	20.5	-93%
Other income, net	(2.1)	(9.5)	7.4	-78%
	108.0	39.8	68.2	NM
(Loss) income from continuing operations before income taxes	(91.6)	12.0	(103.6)	NM
Income tax benefit	(12.9)	(1.9)	(11.0)	NM
(Loss) income from continuing operations	(78.7)	13.9	(92.6)	NM
Loss from discontinued operations, net of tax	(0.1)	(4.9)	4.8	-98%

Net (loss) income		(78.8)	9.0	(87.8)	NM
Net loss attributable to noncontrolling interests		(6.7)	(0.8)	0.8	NM
Net income attributable to Preferred share dividends of a subsidiary company		5.9	6.3	(7.1)	NM
Net (loss) income attributable to Atlantic Power Corporation	$	(78.0)	3.5	(81.5)	NM

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	Six months ended June 30, 2014				
	East	West[1]	Wind	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 81.4	$ 43.3	$ 40.0	$	$ 164.7
Energy capacity revenue	55.1	19.7			74.8
Other	26.3	22.3	0.1	0.3	49.0
	162.8	85.3	40.1	0.3	288.5
Project expenses:					
Fuel	78.5	31.7			110.2
Operations and maintenance	27.6	27.0	10.5	2.1	67.2
Development				1.8	1.8
Depreciation and amortization	34.4	26.7	20.1	0.3	81.5
	140.5	85.4	30.6	4.2	260.7
Project other income (expense):					
Change in fair value of derivative instruments	22.8		(9.7)	(1.2)	11.9
Equity in earnings of unconsolidated affiliates	10.7	1.6	(0.2)	(0.2)	11.9
Interest expense, net	(13.3)		(7.1)		(20.4)
Impairment	(14.8)				(14.8)
	5.4	1.6	(17.0)	(1.4)	(11.4)
Project income (loss)	$ 27.7	$ 1.5	$ (7.5)	$ (5.3)	$ 16.4

(1) Excludes Greeley which is designated as discontinued operations.

	Six months ended June 30, 2013				
	East[1]	West[2]	Wind	Un-allocated Corporate[3]	Consolidated Total
Project revenue:					
Energy sales	$ 76.2	$ 41.6	$ 35.7	$ 0.3	$ 153.8
Energy capacity revenue	57.2	20.0			77.2
Other	18.3	24.8		(0.5)	42.6
	151.7	86.4	35.7	(0.2)	273.6
Project expenses:					
Fuel	68.1	29.6			97.7
Operations and maintenance	29.8	30.6	10.2	3.3	73.9
Development				3.5	3.5
Depreciation and amortization	33.7	27.7	21.0	0.3	82.7

		131.6		87.9		31.2		7.1	257.8
Project other income (expense):									
Change in fair value of derivative instruments		19.9				16.9		0.1	36.9
Equity in earnings of unconsolidated affiliates		12.6		1.9		1.3		0.1	15.9
Interest expense, net		(9.2)				(7.4)		(0.2)	(16.8)
Other income (expense), net									
		23.3		1.9		10.8			36.0
Project income (loss)	$	43.4	$	0.4	$	15.3	$	(7.3)	$ 51.8

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Path 15 and Greeley which are designated as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations.

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East

Project income for 2014 decreased $15.7 million from the comparable 2013 period primarily due to:

- decreased project income of $12.8 million at Tunis due primarily to a $14.8 million long-lived asset and goodwill impairment partially offset by decreased maintenance costs from the comparable 2013 period;
- decreased project income of $9.5 million at Piedmont due primarily to a negative $6.7 million non-cash change in the fair value of interest rate swap agreements that was accounted for as a derivative and higher fuel and maintenance expenses in 2014, which were partially offset by higher revenue resulting from increased capacity payments; and
- decreased project income of $7.2 million at Selkirk due primarily to accelerated depreciation resulting from the expiration of the project's PPA in August 2014.

These decreases were partially offset by:

- increased project income of $7.7 million at Orlando due to a $4.6 million non-cash increase in the fair value of natural gas swaps and a $2.2 million increase in revenue from higher capacity payments under its PPA;
- increased project income of $4.4 million at Morris due primarily to lower maintenance expenses as compared to the comparable 2013 period, during which the project underwent a scheduled outage;
- increased project income of $3.0 million at Nipigon due primarily to a positive $2.5 million non-cash change in the fair value of fuel contracts that were accounted for as derivatives; and
- increased project income of $2.2 million at North Bay due primarily to lower fuel expense resulting from lower fuel costs and lower maintenance expenses as compared to the comparable 2013 period during which the project underwent a scheduled outage.

West

Project income for 2014 increased $1.1 million from the comparable 2013 period primarily due to:

- increased project income of $3.9 million at Naval Training Center due primarily to decreased maintenance as compared to the comparable 2013 period, during which the project underwent a scheduled turbine overhaul.

Wind

Project income for 2014 decreased $22.8 million from the comparable 2013 period primarily due to:

- decreased project income from Rockland of $10.8 million due primarily to a negative $11.9 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives; and
- decreased project income from Meadow Creek of $9.4 million due primarily to a negative $14.7 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives, partially offset by $3.7 million of increased revenue due to higher generation.

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Un-allocated Corporate

Total project loss decreased $2.0 million from the comparable 2013 period primarily due to a $1.7 million decrease in development costs and a $1.1 million decrease in administrative costs at Ridgeline related to administrative and development reduction initiatives undertaken during the comparable 2013 period.

Administrative and other expenses (income)

Administration

Administration expense decreased $2.6 million or 13% from the comparable 2013 period primarily due to transactional fees incurred during 2013 in connection with project divestitures.

Interest, net

Interest expense increased $42.9 or 84% million from the comparable 2013 period primarily due to $23.3 million of make-whole premiums paid to redeem the Series A Notes and Series B Notes, as well as $16.4 million of premiums paid and non-cash deferred financing costs written off for the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes.

Foreign exchange gain

Foreign exchange gain decreased $20.5 million or 93% from the comparable 2013 period primarily due to a $26.4 million decrease in unrealized gain in the revaluation of instruments denominated in Canadian dollars and a $13.2 million decrease in realized gains on the settlement of foreign currency forward contracts, offset by a $19.1 million decrease in unrealized loss on foreign exchange forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.07 and 1.05 at June 30, 2014 and 2013, respectively, an increase of 0.3% in the six months ended June 30, 2014 compared to an increase of 5.7% in the six months ended June 30, 2013.

Other income, net

Other income, net decreased $7.4 million or 78% from the 2013 comparable period primarily due to a $2.1 million non-cash gain recorded for the sale of Greeley in March 2014 as compared to a $10.3 million gain and management fee agreement termination fee in the second quarter of 2013 resulting from the sale of Path 15.

Income tax benefit

Income tax benefit for the six months ended June, 2014 was $12.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $23.8 million. The primary items impacting the tax rate for the six months ended June 30, 2014 were $29.3 million relating to a change in the valuation allowance, $2.6 million relating to minority interest adjustments, and $0.5 million of other permanent differences. These items were partially offset by $11.1 million of capital losses recognized on tax restructuring, $9.2 million relating to operating in higher tax rate jurisdictions, and $1.2 million relating to foreign exchange.

Income tax benefit from continuing operations for the six months ended June 30, 2013 was $1.9 million. The difference between the actual tax benefit of $1.9 million and the expected income tax expense of $1.7 million, based on the Canadian enacted statutory rate of 25%, is primarily due to permanent difference benefits of $19.7 million generated from U.S. Treasury grant proceeds, production tax credits and foreign exchange differences, partially offset by a $12.7 million increase in the valuation allowance, $2.6 million in dividend withholding and preferred share taxes, and $0.8 of other permanent differences.

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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. 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 the projects to maintain certain levels of availability. Although the availability in the table below fluctuates from year to year, the majority of projects with reduced availability were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted their capacity payments, the impact was approximately $4.7 million of lower capacity revenue for the six months ended June 30, 2014. The terms of our PPAs provide for certain levels of planned and unplanned outages.

Generation

	Three months ended June 30,		
(in Net MWh)	**2014**	**2013**	**% change 2014 vs. 2013**
Segment			
East[1]	958.3	960.3	-0.2%
West[2]	543.6	558.5	-2.7%
Wind	520.9	489.8	6.3%
Total	2,022.8	2,008.6	0.7%

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Delta-Person, which was sold in July 2014, and Gregory, which was sold in August 2013. Excludes Greeley, which was sold in March 2014 and is designated as discontinued operations.

Three months ended June 30, 2014 compared with three months ended June 30, 2013

Aggregate power generation for the three months ended June 30, 2014 increased 0.7% from the comparable 2013 period primarily due to:

- increased generation in the Wind segment due to higher generation at Meadow Creek and Canadian Hills.

This increase was partially offset by:

- decreased generation in the West segment due to lower dispatch at Manchief, partially offset by increased generation at Williams Lake which had a planned major maintenance outage in the comparable 2013 period.

	Six months ended June 30,		
(in Net MWh)	**2014**	**2013**	**% change 2014 vs. 2013**
Segment			
East[1]	2,052.5	1,902.2	7.9%
West[2]	1,099.7	1,062.6	3.5%
Wind	958.5	925.9	3.5%
Total	4,110.7	3,890.7	5.7%

(1)

Excludes the Florida Projects which are designated as discontinued operations.

(2)

Excludes Delta-Person, which was sold in July 2014, and Gregory, which was sold August in 2013. Excludes Greeley, which was sold in March 2014 and is designated as discontinued operations.

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Six months ended June 30, 2014 compared with six months ended June 30, 2013

Aggregate power generation for the six months ended June 30, 2014 increased 5.7% from the comparable 2013 period primarily due to:

- increased generation in the East segment due to Piedmont, which achieved commercial operations in April 2013, and increased dispatch at Chambers;
- increased generation in the West segment due to increased generation at Frederickson, partially offset by lower dispatch at Manchief; and
- increased generation in the Wind segment due to higher generation at Meadow Creek and Rockland.

Availability

	Three months ended June 30,		
	2014	2013	% change 2014 vs. 2013
Segment			
East[(1)]	90.2%	93.9%	-3.9%
West[(2)]	90.9%	88.7%	2.5%
Wind	98.3%	98.6%	-0.3%
Weighted average	91.2%	92.9%	-1.8%

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Delta-Person, which was sold in July 2014, and Gregory, which was sold in August 2013. Excludes Greeley, which was sold in March 2014 and is designated as discontinued operations.

Weighted average availability for the three months ended June 30, 2014 decreased 1.8% to 91.2% from the comparable 2013 period primarily due to:

- decreased availability in the East segment resulting from decreased availability at Cadillac and Orlando, each of which underwent scheduled maintenance outages during the current period.

This decrease was partially offset by:

- increased availability in the West segment resulting from increased availability at Williams Lake, Mamquam and Moresby Lake, each of which experienced maintenance outages in the comparable 2013 period, partially offset by decreases at Oxnard and Naval Station which had maintenance outages in 2014.

Generation and availability statistics for the West segment exclude the Greeley, Gregory, and Delta-Person projects, which have been sold. For the three months ended June 30, 2013, total generation and availability was (i) for Greeley, 67.6 MWh and 99.6%, respectively, (ii) for Gregory, 110.9 MWh and 98.7%, respectively, and (iii) for Delta-Person, 1.9 MWh and 97.0%, respectively.

Generation and availability statistics for the East segment for 2013 exclude the Florida Projects, which were sold in April 2013 and are accounted for as a component of discontinued operations. For the three months ended June 30, 2013 total generation and availability was (i) for Auburndale, 60

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265.9 MWh and 98.2%, respectively, (ii) for Lake, 122.6 MWh and 99.7%, respectively and (iii) for Pasco, 95.3 MWh and 95.0%, respectively.

	Six months ended June 30,		
	2014	2013	% change 2014 vs. 2013
Segment			
East[(1)]	92.1%	94.9%	-2.9%
West[(2)]	90.2%	91.1%	-0.9%
Wind	95.8%	98.4%	-2.6%
Weighted average	91.9%	93.9%	-2.1%

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Delta-Person, which was sold in July 2014, and Gregory, which was sold in August 2013. Excludes Greeley, which was sold in March 2014 and is designated as discontinued operations.

Weighted average availability for the six months ended June 30, 2014 decreased 2.1% to 91.9% from 2013 primarily due to:

- decreased availability in the East Segment resulting from decreased availability at Kapuskasing which had a forced outage and at Cadillac, Chambers and Orlando, which underwent planned maintenance outages during 2014; and

- decreased availability in the Wind Segment resulting from decreased availability at Canadian Hills, which underwent a weather-related outage in the first quarter of 2014.

Generation and availability statistics for the West segment exclude the Greeley, Gregory, and Delta-Person projects, which have been sold. For the six months ended June 30, 2014, total generation and availability was (i) for Greeley, 97.8 MWh and 99.8%, respectively, (ii) for Gregory, 210.9 MWh and 97.7%, respectively, and (iii) for Delta-Person, 2.0 MWh and 96.9%, respectively.

Generation and availability statistics for the East segment for 2013 exclude the Florida Projects, which were sold in April 2013 and are accounted for as a component of discontinued operations. For the six months ended June 30, 2013 total generation and availability was (i) for Auburndale, 270.0 MWh and 98.8%, respectively, (ii) for Lake, 240.0 MWh and 97.3%, respectively and (iii) for Pasco, 40 MWh and 91.6%, respectively.

Supplementary Non-GAAP Financial Information

A key measure we use to evaluate the results of our business is Free Cash Flow. Free Cash Flow is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Free Cash Flow is a relevant supplemental measure of our ability to pay for additional debt reduction, fund internal or external growth, pay any dividends to our shareholders, or many other allocations of any available cash. A reconciliation of Free Cash Flow to cash flows from operating activities, the most directly comparable GAAP measure, is set out below under "Free Cash Flow." Free Cash Flow is comparable to Cash Available for Distribution, the non-GAAP measure we previously used to evaluate the results of our business. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Free Cash Flow is cash distributions received from projects. These distributions are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service, capital expenditures, dividends paid on preferred shares of a subsidiary

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company, distributions to noncontrolling interests and adjusted for changes in project-level working capital and cash reserves. 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 use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of Project Adjusted EBITDA to project income (loss) is provided under "Project Adjusted EBITDA" below and a reconciliation of Project Adjusted EBITDA by segment to project income (loss) by segment is provided in Note 14 to the consolidated financial statements of this Quarterly Report on Form 10-Q. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Project Adjusted EBITDA

	Three months ended June 30, 2014	Three months ended June 30, 2013	$ change 2014 vs 2013	Six months ended June 30, 2014	Six months ended June 30, 2013	$ change 2014 vs 2013
Project Adjusted EBITDA by segment						
East[1]	$ 38.5	$ 29.4	$ 9.1	$ 84.0	$ 78.5	$ 5.5
West[2]	22.9	14.1	8.8	34.1	34.7	(0.6)
Wind	17.2	15.5	1.7	35.1	30.5	4.6
Un-allocated Corporate[3]	(3.6)	(3.1)	(0.5)	(3.6)	(7.6)	4.0
Total	75.0	55.9	19.1	149.6	136.1	13.5
Reconciliation to project income						
Depreciation and amortization	52.3	50.5	1.8	104.7	102.3	2.4
Interest expense, net	8.6	9.5	(0.9)	24.7	19.7	5.0
Change in the fair value of derivative instruments	3.1	(26.8)	29.9	(11.0)	(38.3)	27.3
Other expense	14.8	2.4	12.4	14.8	0.6	14.2
Project income	$ (3.8)	$ 20.3	$ (24.1)	$ 16.4	$ 51.8	$ (35.4)

(1) Excludes the Florida Projects which are designated as discontinued operations.

(2) Excludes Path 15 and Greeley which are designated as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations.

East

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

	Three months ended June 30, 2014	Three months ended June 30, 2013	% change 2014 vs. 2013
East			

Project Adjusted EBITDA	$ 38.5	$ 29.4	31%

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Three months ended June 30, 2014 compared with three months ended June 30, 2013

Project Adjusted EBITDA for the three months ended June 30, 2014 increased $9.1 million or 31% from the comparable 2013 period primarily due to increases in Project Adjusted EBITDA of:

$2.3 million at Kapuskasing and $2.0 million at North Bay, primarily attributable to lower maintenance expenses at the projects as compared to the comparable 2013 period, during which each of the projects underwent a scheduled turbine overhaul.

Project Adjusted EBITDA for the East segment excludes the Florida Projects, which were sold in April 2013 and are accounted for as a component of discontinued operations for the three months ended June 30, 2013. Project Adjusted EBITDA for the Florida Projects was $2.7 million for the three months ended June 30, 2013.

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

	Six months ended June 30,		
	2014	**2013**	**% change 2014 vs. 2013**
East			
Project Adjusted EBITDA	$ 84.0	$ 78.5	7%

Six months ended June 30, 2014 compared with six months ended June 30, 2013

Project Adjusted EBITDA for the six months ended June 30, 2014 increased $5.5 million or 7% from the comparable 2013 period primarily due to increases in Project Adjusted EBITDA of:

$4.4 million at Morris primarily attributable to lower maintenance costs, lower fuel expenses, and higher revenues than the comparable 2013 period.

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

$1.4 million at Cadillac, which incurred decreased capacity revenue and increased maintenance expenses resulting from a scheduled annual outage during the period.

Project Adjusted EBITDA for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations for the six months ended June 30, 2013. Project Adjusted EBITDA for the Florida Projects was $27.3 million for the six months ended June 30, 2013.

West

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

	Three months ended June 30,		
	2014	**2013**	**% change 2014 vs. 2013**
West			
Project Adjusted EBITDA	$ 22.9	$ 14.1	62%

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Three months ended June 30, 2014 compared with three months ended June 30, 2013

Project Adjusted EBITDA for the three months ended June 30, 2014 increased $8.8 million or 62% from the comparable 2013 period primarily due to increases in Project Adjusted EBITDA of:

- $3.7 million at Naval Training Center primarily attributable to lower maintenance expenses as compared to the comparable 2013 period, during which the project underwent schedule turbine maintenance;

- $3.1 million at Williams Lake primarily attributable to lower maintenance expenses as compared to the comparable 2013 period during which the project underwent a scheduled turbine overhaul; and

- $2.3 million at Mamquam primarily attributable to lower maintenance expenses as compared to the comparable 2013 period during which the project underwent a scheduled generator and turbine overhaul.

Project Adjusted EBITDA for the West segment excludes the Greeley project, which was sold in March 2014 and is accounted for as a component of discontinued operations for the three months ended June 30, 2013. Project Adjusted EBITDA for Greeley was $1.1 million for the three months ended June 30, 2013. Project Adjusted EBITDA for the West segment also excludes the Path 15 project, which was sold in April 2013 and is accounted for as a component of discontinued operations for the three months ended June 30, 2013. Project Adjusted EBITDA for Path 15 was $2.8 million for the three months June 30, 2013.

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

	Six months ended June 30, 2014	2013	% change 2014 vs. 2013
West			
Project Adjusted EBITDA	$ 34.1	$ 34.7	-2%

Six months ended June 30, 2014 compared with six months ended June 30, 2013

Project Adjusted EBITDA for the six months ended June 30, 2014 decreased $0.6 million or 2% from the comparable 2013 period primarily due to a total of $4.7 million of individually immaterial decreases in Project Adjusted EBITDA at various West projects, partially offset by an increase in Project Adjusted EBITDA of $3.9 million at Naval Training Center as a result of lower maintenance expenses as compared to the comparable 2013 period, during which the project underwent scheduled turbine maintenance.

Project Adjusted EBITDA for the West segment excludes the Greeley project, which was sold in March 2014 and is accounted for as a component of discontinued operations for the six months ended June 30, 2014 and 2013. Project Adjusted EBITDA for Greeley was ($0.1) and $2.0 million for the six months ended June 30, 2014 and 2013, respectively. Project Adjusted EBITDA for the West segment also excludes the Path 15 project, which was sold in April 2013 and is accounted for as a component of discontinued operations for the six months ended June 30, 2013. Project Adjusted EBITDA for Path 15 was $9.0 million for the three months June 30, 2013.

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Wind

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

	Three months ended June 30,		
	2014	2013	% change 2014 vs. 2013
Wind			
Project Adjusted EBITDA	$ 17.2	$ 15.5	11%

Three months ended June 30, 2014 compared with three months ended June 30, 2013

Project Adjusted EBITDA for the three months ended June 30, 2014 did not change materially from the comparable 2013 period and each of our wind projects had a slight Project Adjusted EBITDA improvement as compared to the comparable 2013 period.

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

	Six months ended June 30,		
	2014	2013	% change 2014 vs. 2013
Wind			
Project Adjusted EBITDA	$ 35.1	$ 30.5	15%

Six months ended June 30, 2014 compared with six months ended June 30, 2013

Project Adjusted EBITDA for the six months ended June 30, 2014 increased $4.6 million or 15% from the comparable 2013 period primarily due to an increase in Project Adjusted EBITDA of:

$3.6 million at Meadow Creek attributable to higher generation than in the comparable 2013 period.

Un-Allocated Corporate

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

	Three months ended June 30,		
	2014	2013	% change 2014 vs. 2013
Un-Allocated Corporate			
Project Adjusted EBITDA	$ (3.6)	$ (3.1)	16%

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Three months ended June 30, 2014 compared with three months ended June 30, 2013

Project Adjusted EBITDA for the three months ended June 30, 2014 did not change materially from the comparable 2013 period.

	Six months ended June 30,		
	2014	**2013**	**% change 2014 vs. 2013**
Un-Allocated Corporate			
Project Adjusted EBITDA	$ (3.6)	$ (7.6)	53%

Six months ended June 30, 2014 compared with six months ended June 30, 2013

Project Adjusted EBITDA for the six months ended June 30, 2014 increased $4.0 million or 53% from the comparable 2013 period primarily due to decreased development costs at Ridgeline and a decrease in administrative costs related to administrative and development reduction initiatives undertaken during the comparable 2013 period.

Free Cash Flow

Free Cash Flow was $(15.1) million and $(7.5) million for the three months ended June 30, 2014 and 2013, respectively, and $(61.0) million and $74.5 million for the six months ended June 30, 2014 and 2013, respectively. The $7.6 million decrease in Free Cash Flow for the three months ended June 30, 2014 as compared to the same period in 2013 was due primarily to $37.5 million of term loan facility repayments by the Partnership, partially offset by $26.8 million of increased cash flows from operations. The increase in cash flows from operations is primarily due to $16.8 million of increased distributions from equity investments and a $6.9 million increase in working capital.

The $135.5 million decrease in Free Cash Flow for the six months ended June 30, 2014 as compared to the same period in 2013 was due primarily to $37.5 million of term loan facility repayments by the Partnership and a $91.4 million decrease in cash flows from operating activities. The decrease in cash flows from operating activities is primarily due to $46.8 million of interest expense related to make-whole, accrued interest and premium payments made in connection with the redemption of the Series A and Series B Notes, the Curtis Palmer Notes and the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014, a $32.8 million decrease in loss from discontinued operations and a $29.3 million decrease in working capital from the comparable 2013 period. The decrease in working capital is due to a $31.6 million decrease in prepaid and other assets due to the collection of security deposits related to our recently completed construction projects, such as Piedmont, Canadian Hills and Meadow Creek, in the first quarter of 2013.

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The table below presents our calculation of Free Cash Flow for the three and six months ended June 30, 2014 and 2013, and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Cash flows from operating activities	$ 34.0	$ 7.2	$ 5.5	$ 96.9
Term loan facility repayments[1]	(37.5)		(37.5)	
Project-level debt repayments	(5.5)	(7.9)	(15.4)	(10.5)
Purchases of property, plant and equipment[2]	0.1	(1.7)	(2.5)	(2.7)
Distributions to noncontrolling interests[3]	(3.1)	(2.0)	(5.2)	(2.9)
Dividends on preferred shares of a subsidiary company	(3.1)	(3.1)	(5.9)	(6.3)
Free Cash Flow[4]	$ (15.1)	$ (7.5)	$ (61.0)	$ 74.5

(1) Includes mandatory 1% annual amortization and 50% excess cash flow repayments by the Partnership.

(2) Excludes construction costs related to our Canadian Hills and Piedmont projects in 2014 and our Canadian Hills, Piedmont and Meadow Creek projects in 2013.

(3) Distributions to noncontrolling interests primarily include distributions, if any, to the tax equity investors at Canadian Hills and to the other 50% owner of Rockland.

(4) Free Cash Flow is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information" above. This table should be read together with the below table under "Consolidated Cash Flows" that sets forth Net cash provided by (used in) investing activities and Net cash (used in) provided by financing activities for the three and six months ended June 30, 2014 and 2013.

Consolidated Cash Flows

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

	2014	2013	Change
Net cash provided by operating activities	$ 5.5	$ 96.9	$ (91.4)
Net cash provided by investing activities	75.4	151.3	(75.9)
Net cash used in financing activities	(81.9)	(119.3)	37.4

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Net cash provided by operating activities

Changes to net cash provided by operating activities were driven by:

	Six months ended June 30, 2014
Increase in net loss primarily due to interest payment and make-whole and other premiums on retired debt	$ (87.8)
Decrease in the loss at discontinued operations from the sale of the Florida Projects, Path and Rollcast	(32.8)
Decrease in earnings from unconsolidated affiliates	4.0
Change in unrealized foreign exchange gain on Canadian dollar denominated instruments	7.3
Change in depreciation and amortization	(11.3)
Change in deferred income taxes	(7.0)
Change in distributions from unconsolidated affiliates	19.8
Changes in working capital	(29.3)
Change in fair value of derivative instruments	35.8
Change in impairment charges	9.9
	$ (91.4)

Net cash provided by investing activities

Changes to net cash provided by investing activities were driven by:

	Six months ended June 30, 2014
Decrease in proceeds from asset sales of the Florida Projects and Path 15 in April 2013	$ (147.3)
Less restricted cash primarily due to the release of the $75 million requirement under the prior credit facility	97.8
Decrease in treasury grant proceeds from Piedmont and Meadow Creek received in 2013	(53.7)
Change in construction in process	27.0
Other	0.3
	$ (75.9)

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Net cash used in financing activities

Changes to net cash used in financing activities were driven by:

	Six months ended June 30, 2014
Increase in net proceeds and payments on project-level and corporate debt primarily due to proceeds from the New Senior Secured Credit Facilities offset by repayments of the Series A and Series B Unsecured Notes, Senior Unsecured Notes of Curtis Palmer and partial repurchase of the 9.0% Notes in the first quarter of 2014	$ 56.2
Increased deferred financing costs primarily due to the issuance of the New Senior Secured Credit Facility in the first quarter of 2014	(38.8)
Decreased payments of dividends to common shareholders due to the dividend reduction in March 2013 offset by increased distributions to non-controlling interests	17.4
Decrease in proceeds from project level debt	(20.8)
Decrease in payments for revolving credit facility borrowings	67.0
Decrease in equity contribution from noncontrolling interest	(44.6)
Other	1.0
	$ 37.4

Liquidity and Capital Resources

	June 30, 2014	December 31, 2013
Cash and cash equivalents	$ 157.6	$ 158.6
Restricted cash[(1)]	35.7	114.2
Total	193.3	272.8
Revolving credit facility availability	103.0	52.8
Total liquidity	$ 296.3	$ 325.6

(1) The decrease in restricted cash is primarily due to the release of the $75 million reserve requirement under the prior credit facility.

Overview

Our primary source of liquidity is distributions from our projects and availability under our New 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 August 31, 2014 (at Selkirk, which represented 5.6% and 6.1% of our Project Adjusted EBITDA for the three and six months ended June 30, 2014, respectively) to December 2037. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements or may elect to operate certain facilities in the merchant market upon expiration of their PPAs. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See "Risk Factors Risks

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Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities or fund our operations" in our Annual Report on Form 10-K for the year ended December 31, 2013.

We expect to reinvest approximately $35 to $40 million in 2014 (of which $2.4 million and $12.5 million was reinvested in the three and six months ended June 30, 2014) in our portfolio in the form of project capital expenditures and major maintenance expenses. Such investments are generally paid at the project level. See " Capital and Major Expenditures" in our Annual Report on Form 10-K for the year ended December 31, 2013. We do not expect any other material or unusual requirements for cash outflows for 2014 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.

New Senior Secured Credit Facilities

On February 24, 2014 the Partnership, our wholly-owned indirect subsidiary, entered into the New Senior Secured Credit Facilities, including the New Term Loan Facility, comprising $600 million in aggregate principal amount, and the New Revolving Credit Facility with a capacity of $210 million. Borrowings under the New Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the New Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively (3.75% at August 7, 2014). The Adjusted Eurodollar Rate cannot be less than 1.00% (1.00% at August 7, 2014).

In connection with the funding of the New Senior Secured Credit Facilities, we terminated our prior revolving credit facility on February 26, 2014.

The New Term Loan Facility matures on February 24, 2021. The revolving commitments under the New Revolving Credit Facility terminate on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the New Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit.

The New Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The New Senior Secured Credit Facilities are not otherwise guaranteed or secured by us or any of our subsidiaries (other than the Partnership subsidiary guarantors). The New Senior Secured Credit Facilities also have a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The debt service reserve requirement was funded with a $15.8 million letter of credit.

The Partnership's existing Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the

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MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership granted an equal and ratable security interest in the collateral package securing the New Senior Secured Credit Facilities under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the New Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the New Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144.1 million ($107.6 million as of August 7, 2014) were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used to (i) satisfy a debt service reserve requirement in an amount equivalent to six months of debt service (approximately $15.8 million) and (ii) support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries used the proceeds from the New Term Loan Facility under the New Senior Secured Credit Facilities to:

- redeem in whole, at a price equal to par plus $31.1 million of accrued interest and make-whole premiums (i) the $150 million aggregate principal amount outstanding of the Series A Notes and the $75 million aggregate principal amount outstanding of the Series B Notes issued by Atlantic

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Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

pay transaction costs and expenses of approximately $40.0 million including banking, legal and consulting fees which were capitalized as deferred financing costs; and

make a distribution to us in the amount of $122 million which was used, in addition to cash on hand, to repurchase $140.1 million aggregate principal amount of the 9.0% Notes, make $15.7 million in accrued interest and premium payments as part of the aggregate repurchase price, and $0.1 million in commission fees associated with the repurchases. Having substantially completed our previously announced intention to repurchase or redeem up to $150 million aggregate principal amount of the 9.0% Notes, we do not expect at this time to repurchase or redeem any additional amounts of the 9.0% Notes, but reserves the right to do so in the future.

In connection with the termination of our prior credit facility, we terminated the interest rate swap at Epsilon Power Partners, a wholly owned subsidiary, a portion of our natural gas swaps at Orlando and foreign exchange forward contracts at the Partnership. As a result of the termination of these contracts, we recorded $2.6 million of interest expense, $4.0 million of fuel expense and $0.4 million of foreign exchange loss, respectively. We intend to explore opportunities to enter into additional fuel swaps and forward contracts with the new banking group associated with the New Senior Secured Credit Facility.

In addition, the prior credit facility contained certain guaranties, which were terminated in connection with the termination of the prior credit facility. In addition, the terms of the 9.0% Notes provide that the guarantors of the prior credit facility guarantee the 9.0% Notes. As a result, upon termination of our prior credit facility and its related guaranties, the guaranties under the 9.0% Notes were cancelled and the guarantors of the 9.0% Notes were automatically released from all of their obligations under such guaranties.

Impact of the New Senior Secured Credit Facilities

As previously disclosed with respect to the impact of the New Senior Secured Credit Facilities in our Current Report on Form 8-K filed on January 30, 2014 and in our Annual Report on Form 10-K for the year ended December 31, 2013, due to the aggregate impact of the up-front costs resulting from the prepayments on our indebtedness described above, including the premium payment and charges for unamortized debt discount and fee expenses and premiums as part of the overall purchase price in respect of the repurchases of the 9.0% Notes (all such up-front costs, collectively, the "Prepayment Charges"), which were reflected as interest expense in our 2014 first quarter results, we no longer satisfy the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing the 9.0% Notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments. As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (approximately $61 million at June 30, 2014) until such time that we satisfy the fixed charge coverage ratio test. We have declared seven monthly dividends in January through July 2014 totaling approximately $25.6 million that were subject to the basket provision.

For the trailing twelve months ended June 30, 2014, dividend payments to our shareholders totaled approximately Cdn$48.1 million, reflecting the lower Cdn$0.03333 per common share monthly dividend first declared in March 2013. The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, any similar prepayment charges incurred in connection with any further debt reduction would also be reflected in the calculation of the

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fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2014:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2014	2015	2016	2017	2018	Thereafter
Senior Secured Term Loan Facility[1]	February 2021	4.75% - 5.90%	$ 562.5	$ 3.0	$ 6.0	$ 6.0	$ 6.0	$ 6.0	$ 535.5
Atlantic Power Corporation Notes	November 2018	9.0%	319.9					319.9	
Atlantic Power Income LP Note	June 2036	6.0%	196.8						196.8
Convertible Debenture[2]	October 2014	6.5%	42.0	42.0					
Convertible Debenture	March 2017	6.3%	63.3				63.3		
Convertible Debenture	June 2017	5.6%	75.4				75.4		
Convertible Debenture	June 2019	5.8%	130.0						130.0
Convertible Debenture	December 2019	6.0%	93.7						93.7
Total Corporate Debt			$ 1,483.6	$ 45.0	$ 6.0	$ 6.0	$ 144.7	$ 325.9	$ 956.0

(1) In addition to the annual principal payments described herein, the Credit Agreement requires payment of 50% of the excess cash flow of the Partnership and its subsidiaries. On May 5, 2014 we entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $199.0 million notional amount of the $562.5 million outstanding aggregate borrowings. See Note 8, Accounting for derivative instruments and hedging activities for further details.

(2) We expect to repay the Cdn$44.8 million aggregate principal amount of convertible debentures due October 2014 at maturity with cash on hand.

Project-Level Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at June 30, 2014. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. At August 7, 2014, all of our projects, except for Piedmont, were in compliance with the covenants contained in project-level debt. During the first quarter of 2014, Piedmont underwent forced maintenance outages that resulted in the project not meeting its debt service coverage ratio covenant as of June 30, 2014. We do not expect Piedmont to meet its debt service coverage ratio covenant or make distributions for at least the next twelve months. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. See Note 6, *Long-term debt Non-Recourse Debt*.

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The range of interest rates presented represents the rates in effect at June 30, 2014. 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	2014	2015	2016	2017	2018	Thereafter
Consolidated Projects:									
Epsilon Power Partners	January 2019	3.5%	$ 28.0	$ 2.5	$ 5.8	$ 6.0	$ 6.3	$ 6.5	$ 0.9
Piedmont	August 2018	5.2%	68.3	4.3	4.5	3.3	4.7	51.5	
Cadillac	August 2025	6.0% - 8.0%	34.4	1.0	3.9	2.5	3.0	3.0	21.0
Meadow Creek	December 2024	2.9% - 5.6%	167.3	2.4	4.6	5.3	5.3	6.0	143.7
Rockland[(1)]	June 2027	6.4% - 6.7%	84.4	0.5	1.8	1.9	2.2	2.5	75.5
Total Consolidated Projects			382.4	10.7	20.6	19.0	21.5	69.5	241.1
Equity Method Projects:									
Chambers[(2)]	December 2019 and 2023	4.5% - 5.0%	43.2	0.1	0.2	0.1			42.8
Delta-Person[(3)]	December 2018	1.8%	5.8	0.7	1.4	1.5	1.1	1.0	0.1
Goshen	December 2022	2.9% - 7.1%	24.2	0.3	0.5	0.7	0.9	1.0	20.8
Idaho Wind	December 2027	5.8%	44.6	0.3	2.6	2.5	2.7	2.9	33.6
Total Equity Method Projects			117.8	1.4	4.7	4.8	4.7	4.9	97.3
Total Project-Level Debt			$ 500.2	$ 12.1	$ 25.3	$ 23.8	$ 26.2	$ 74.4	$ 338.4

(1) We own a 50% interest in the Rockland project. We consolidate Rockland because as the managing member of the project, we have the control to direct most significant decisions in the day to day operations of the project. The maturities above represent 100% of the future principal payments on the Rockland debt.

(2) 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.

(3) We sold our 40% interest in Delta-Person in July 2014.

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 notes and other corporate and project level debt, funding collateral and capital expenditures, including major maintenance and business development costs and dividend payments, if and when declared by our board of directors, to our common shareholders and preferred shareholders of a subsidiary company. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non-recourse operating level debt, although we can provide no assurances regarding the availability of public or private financing on acceptable terms or at all. In addition, we expect to repay our Cdn$44.8 million aggregate principal amount of convertible debentures due October 2014 at maturity with cash on hand.

Capital and Major 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 major expenditures relate to planned repairs and maintenance and are expensed when incurred.

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We expect to reinvest approximately $35 to $40 million in 2014 in our portfolio in the form of project capital expenditures and major maintenance expenses. As explained above, these investments are generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major 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 major 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 major maintenance expenses may exceed the projected level in 2014 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

Of the $35 to $40 million of expected project capital expenditures and major maintenance expenses in 2014, we invested approximately $12.5 million in the six months ended June 30, 2014. In all cases, scheduled maintenance outages during the six months ended June 30, 2014 occurred at such times that did not materially impact the facilities' availability requirements under their respective PPAs.

Recently Adopted and Recently Issued Accounting Guidance

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

Off-Balance Sheet Arrangements

As of June 30, 2014, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 8 to the consolidated financial statements, *Accounting for derivative instruments and hedging activities* for additional information.

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas, biomass and coal prices. See "Item 1A. Risk Factors Risks Related to Our Business and Our Projects Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects" in our Annual Report on Form 10-K for the year ended December 31, 2013. We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long-term fuel contracts, where we lock in a set quantity of fuel at a predetermined price or (iii) pass-through arrangements, whereby the cost of fuel is borne by the ultimate offtaker. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We have entered into various natural gas swaps to effectively fix the price of 7.1 million Mmbtu of future natural gas purchases at Orlando, which is approximately 100% of our share of the expected on-peak natural gas purchases at the project through 2016 or approximately 89%, 62% and 63% of our share of the expected base load natural gas purchases for 2014, 2015 and 2016, respectively. Because projected on-peak gas exposure is fully hedged, a $1.00 MMBtu change in the price of natural gas would not impact estimated cash distributions for the remainder of 2014.

Electricity Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity prices when our projects operate with no PPA or at projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers, Morris, and Selkirk (whose PPA expires on August 31, 2014, and which represented 5.6% and 6.1% of our Project Adjusted EBITDA for the three and six months ended June 30, 2014, respectively) projects. We are currently in negotiations with counterparties regarding the renewal or entry into new power purchase agreements. No assurance can be provided that we will be able to renew or enter into new power purchase agreements on favorable terms or at all. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition" and "Risk Factors Risks Related to Our Business and Our Projects Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating

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margin of these projects and on our business, results of operations and financial condition" in our Annual Report on Form 10-K for the year ended December 31, 2013.

At our 40% owned Chambers project, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is profitable to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. In 2014, projected cash distributions from Chambers would change by approximately $0.9 million per 10% change in the PJM-East spot price of electricity based on a forecasted around the clock ("ATC") price of $38.31 and certain other assumptions.

At Morris, where we own 100% of the project, the facility can sell approximately 100 MW above the off-taker's demand into the grid at market prices. If market prices do not justify the increased generation the project has no requirement to sell power in excess of the off-taker's demand which can negatively impact operating margins. In 2014, projected cash distributions from Morris would change by approximately $0.7 million per 10% change in the spot price of electricity based on the current level of approximately 175,000 MWh grid sales and all other variables being held constant.

At Selkirk, where we own 18.5% of the project, 80 MW, or 23% of the total 345 MW net project capacity is currently not contracted and is sold into the spot power market or not sold at all if market prices do not support profitable operation of that portion of the facility. The current PPA at Selkirk for the remainder of its output expires on August 31, 2014, which could result in an increase to 100% of capacity not contracted and therefore sold at market power prices. In 2014, projected distributions at Selkirk through the term of the PPA would change by approximately $0.2 million per 10% change in the forecasted spot price of electricity.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our project may not be able to secure a new agreement and could be exposed to sell power at spot market price. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition." in our Annual Report on Form 10-K for the year ended December 31, 2013. It is possible that subsequent PPAs or the spot market may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

Foreign Currency Exchange Risk

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars but we pay dividends to shareholders, if and when declared by the board of directors, and interest on corporate level long-term debt and all but one of our convertible debentures, predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on any future payments of dividends to shareholders. From time to time, we execute this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars. These foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counter-party's credit risk. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

On April 2, 2014, we executed a new foreign currency forward contract in which we agreed to sell $41.0 million on September 30, 2014 and receive Cdn$45.3 million at a foreign exchange rate of Cdn$1.105 per U.S. dollar in order to mitigate the foreign exchange risk on the retirement of the Cdn$44.8 million ($41.3 million at August 7, 2014) convertible debentures due in October 2014.

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The following table contains the components of recorded foreign exchange (gain) loss for the three and six months ended June 30, 2014 and 2013:

	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Unrealized foreign exchange (gain) loss:				
Convertible debentures and other	$ 16.7	$ (16.5)	$ (1.1)	$ (27.5)
Forward contracts	(1.4)	12.8	(0.3)	18.8
	15.3	(3.7)	(1.4)	(8.7)
Realized foreign exchange loss (gains) on forward contract settlements		(10.8)	(0.1)	(13.3)
	$ 15.3	$ (14.5)	$ (1.5)	$ (22.0)

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have a $42.8 million impact on the carrying value of the Cdn$210 million MTNs and Cdn$292.8 million convertible debentures denominated in Canadian dollars at June 30, 2014.

Interest Rate Risk

Changes in interest rates impact cash payments that are required on our debt instruments as approximately 22% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at variable rates or is not financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $1.4 million at June 30, 2014. The New Term Loan Facility has a LIBOR floor of 1.00%, and one month LIBOR at June 30, 2014 was approximately 0.16%. If LIBOR were greater than or equal to 1.00%, a change in interest of 100 basis points would change annual interest costs by $4.4 million.

The Partnership

On May 5, 2014 the Partnership entered into interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount of the $600 million aggregate principal amount of borrowings under the New Term Loan Facility. Borrowings under the $600 million New Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.75% all-in rate on the New Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $199.0 million of the New Term Loan Facility cannot be less than 4.91% if the Adjusted Eurodollar Rate is equal to or greater than 1.00%. If the Adjusted Eurodollar Rate is below 1.00%, we will pay interest at a rate equivalent to the minimum 4.75% all-in rate plus any difference between the actual Adjusted Eurodollar Rate and 1.16%.

The interest rate swap agreements are effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations.

Epsilon Power Partners

Epsilon Power Partners, a wholly owned subsidiary, is exposed to changes in interest rates related to its variable-rate non-recourse debt and previously had an interest rate swap to mitigate this exposure. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.37% and had a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. On February 20, 2014, we paid $2.6 million to terminate this contract in connection with the termination of our prior revolving credit facility. We recorded interest expense related to its settlement in the consolidated statement of operations for the three and six months ended June 30, 2014.

Cadillac

We have an interest rate swap at our consolidated Cadillac project to economically fix its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt and changes in its fair market value are recorded in other comprehensive income (loss). The interest rate swap expires on September 30, 2025.

In accounting for the cash flow hedge, gains and losses on the derivative contract are reported in other comprehensive income (loss), but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income (loss). That is, for cash flow hedge, all effective components of the derivative contract's gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income (loss). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income (loss) changes by exactly as much as the derivative contracts and there is no impact on net income (loss) until the expected transaction occurs.

Piedmont

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. Prior to conversion of the Piedmont Construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We recorded $1.0 million of deferred financing costs related to this transaction in the consolidated balance sheets at June 30, 2014. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Meadow Creek

The Meadow Creek project has interest rate swap agreements to economically fix the exposure to changes in interest rates related to 75% of the outstanding variable-rate non-recourse debt at the project. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is

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for the notional amount due on the term loan through December 31, 2024 and fixes the interest rate at 2.3% plus an applicable margin of 2.8%-3.3%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030 fixing the interest rate at 7.2%.

Rockland

The Rockland project entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the expected interest payments through December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3%-2.8%. The second tranche is for the expected interest payments for the period beginning December 31, 2026 and ending December 31, 2031, fixing the interest rate at 7.8%.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this report, and they have concluded that these controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the three and six months ended June 30, 2014, 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.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to numerous legal proceedings, including securities class actions, from time to time. In particular, we and/or certain of our current and former officers have been named as defendants in various class action lawsuits. Due to the nature of these proceedings, the lack of precise damage claims and the type of claims we are subject to, we are unable to determine the ultimate or maximum amount of monetary liability or financial impact, if any, to us in these legal matters, which unless otherwise specified, seek damages from the defendants of material or indeterminate amounts.

Shareholder class action lawsuits

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our President and Chief Executive Officer and a Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Proposed Individual Defendants," and together with Atlantic Power, the "Proposed Defendants") (the "U.S. Actions").

The District Court complaints differed in terms of the identities of the Proposed Individual Defendants they named, as noted above, the named plaintiffs, and the purported class period they alleged (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleged, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Proposed Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Proposed Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Proposed Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that the Proposed Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013.

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On March 31, 2014, the Court entered an order consolidating the five individual U.S. Actions, appointing the Feldman, Shapero, Carter and Smith investor group (one of the six U.S. Lead Plaintiffs Applicants) as Lead Plaintiff and approving Lead Plaintiff's selection of counsel. The Court also granted the parties' joint motion regarding initial case scheduling and directed the parties to resubmit a proposed schedule that contains specific dates. In response to that directive, on April 7, 2014, Lead Plaintiff filed an application and proposed order, which sought an extension of the schedule contained in the joint motion. The application and proposed order requested that: (i) Lead Plaintiff be permitted to file an amended complaint on or before May 30, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before July 29, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before September 24, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 13, 2014. Proposed Defendants did not object to the schedule proposed by Lead Plaintiff. On May 29, 2014, Lead Plaintiff filed a renewed application and proposed order, which sought another extension of the schedule, and on June 3, 2014, Lead Plaintiff and the Proposed Defendants jointly filed a stipulation and proposed order requesting the following revised schedule: (i) Lead Plaintiff be permitted to file an amended complaint on or before June 6, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before August 5, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before October 6, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 20, 2014. On June 3, 2014, the Court entered an order setting this requested schedule.

On June 6, 2014, Lead Plaintiff filed the amended complaint (the "Amended Complaint"). The Amended Complaint names as defendants Barry E. Welch and Terrence Ronan (the "Individual Defendants") and Atlantic Power (together with the Individual Defendants, the "Defendants") and alleges a class period of June 20, 2011 to March 4, 2013 (the "Class Period"). The Amended Complaint makes allegations that are substantially similar to those asserted in the five initial complaints. Specifically, the Amended Complaint alleges, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend, which artificially inflated the price of Atlantic Power's common shares during the class period. The Amended Complaint continues to assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. It also asserts a claim for unjust enrichment against the Individual Defendants. In accordance with the schedule referenced above, Defendants filed their motion to dismiss the consolidated U.S. Action on August 5, 2014.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. As in the U.S. Action, this claim names the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs seeks leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

The Defendants are preparing materials to contest leave and certification.

A schedule for the Plaintiffs' motions and the action is set that contemplates a hearing on leave and certification during the week of March 30, 2015.

The proposed class action in Quebec is stayed until March 30, 2015 to follow the action in Ontario.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously against each of the actions.

Other

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. With respect to such other matters arising in the normal course of business, there are no matters pending as of June 30, 2014 that are expected to have a material impact on our financial position or results of operations or have been reserved for as of June 30, 2014.

Other than as described above, there were no material changes to legal proceedings disclosed in "Item 3. Legal Proceedings" of our Annual Report on Form 10-K for the year ended December 31, 2013.

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, 2013 (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").

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ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.1	Amendment No. 1 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company (incorporated by reference to Exhibit A to Schedule B to the Company's definitive Proxy Statement on Schedule 14A filed on April 30, 2014).
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: August 7, 2014	Atlantic Power Corporation		
	By:	/s/ TERRENCE RONAN	
		Name:	Terrence Ronan
		Title:	*Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*