ATLANTIC POWER CORP
Form 10-Q
August 08, 2013

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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, 2013

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

(617) 977-2400
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 ý	Accelerated filer o	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 5, 2013 was 119,948,759.

ATLANTIC POWER CORPORATION

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THREE AND SIX MONTHS ENDED JUNE 30, 2013

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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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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

	June 30, 2013 (unaudited)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 195.6	$ 60.2
Restricted cash	40.1	28.6
Accounts receivable	71.4	58.5
Current portion of derivative instruments asset (Notes 6 and 7)	0.7	9.5
Inventory	18.1	16.9
Prepayments and other current assets	17.2	13.4
Security deposits	1.1	19.0
Assets held for sale (Note 11)		351.4
Refundable income taxes	1.4	4.2
Total current assets	345.6	561.7
Property, plant, and equipment, net of accumulated depreciation of $128.8 million and $79.2 million at June 30, 2013 and December 31, 2012, respectively	1,932.3	2,055.5
Equity investments in unconsolidated affiliates	410.4	428.7
Other intangible assets, net of accumulated amortization of $106.6 million and $76.9 million at June 30, 2013 and December 31, 2012, respectively	483.6	524.9
Goodwill (Note 4)	331.2	334.7
Derivative instruments asset (Notes 6 and 7)	8.3	11.1
Other assets	56.0	86.1
Total assets	$ 3,567.4	$ 4,002.7
Liabilities		
Current liabilities:		
Accounts payable	$ 13.2	$ 17.8
Accrued interest	17.8	19.0
Other accrued liabilities	46.3	73.7
Revolving credit facility (Note 5)		67.0
Current portion of long-term debt (Note 5)	65.7	121.2
Current portion of derivative instruments liability (Notes 6 and 7)	32.2	33.0
Dividends payable	3.8	11.5
Liabilities held for sale (Note 11)		189.0
Other current liabilities	3.1	3.3
Total current liabilities	182.1	535.5
Long-term debt (Note 5)	1,462.0	1,459.1
Convertible debentures	408.3	424.2
Derivative instruments liability (Notes 6 and 7)	82.0	118.1
Deferred income taxes	155.6	164.0
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $6.5 million and $4.4 million at June 30, 2013 and December 31, 2012, respectively	40.8	44.0
Other non-current liabilities	70.5	71.4
Commitments and contingencies (Note 14)		

Total liabilities		2,401.3		2,816.3
Equity				
Common shares, no par value, unlimited authorized shares; 119,901,246 and 119,446,865 issued and outstanding at June 30, 2013 and December 31, 2012, respectively (Note 12)		1,285.4		1,285.5
Preferred shares issued by a subsidiary company (Note 12)		221.3		221.3
Accumulated other comprehensive income (loss)		(19.5)		9.4
Retained deficit		(597.3)		(565.2)
Total Atlantic Power Corporation shareholders' equity		889.9		951.0
Noncontrolling interest (Note 12)		276.2		235.4
Total equity		1,166.1		1,186.4
Total liabilities and equity	$	3,567.4	$	4,002.7

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,	
	2013	2012	2013	2012
Project revenue:				
Energy sales	$ 68.1	$ 49.4	$ 137.1	$ 109.4
Energy capacity revenue	54.4	37.5	99.2	74.5
Other	16.5	14.5	42.9	36.2
	139.0	101.4	279.2	220.1
Project expenses:				
Fuel	52.0	37.3	101.6	83.5
Operations and maintenance	46.9	37.9	75.2	62.6
Development	1.8		3.5	
Depreciation and amortization	42.2	30.3	83.5	56.8
	142.9	105.5	263.8	202.9
Project other income (expense):				
Change in fair value of derivative instruments (Notes 6 and 7)	24.3	(4.8)	36.9	(62.0)
Equity in earnings of unconsolidated affiliates (Note 3)	8.7	5.5	15.9	8.4
Interest expense, net	(8.7)	(4.1)	(16.7)	(8.1)
Other, net	(4.8)		(4.8)	
	19.5	(3.4)	31.3	(61.7)
Project income (loss)	15.6	(7.5)	46.7	(44.5)
Administrative and other expenses (income):				
Administration	11.8	8.0	20.1	15.7
Interest, net	25.3	21.4	51.2	43.4
Foreign exchange gain (Note 7)	(14.5)	(4.2)	(22.0)	(3.2)
Other income, net	(9.5)	(6.0)	(9.5)	(6.0)
	13.1	19.2	39.8	49.9
Income (loss) from continuing operations before income taxes	2.5	(26.7)	6.9	(94.4)
Income tax expense (benefit) (Note 8)	0.6	(5.3)	(1.9)	(22.2)
Income (loss) from continuing operations	1.9	(21.4)	8.8	(72.2)
Income (loss) from discontinued operations, net of tax (Note 11)	(0.7)	19.3	0.2	30.9
Net income (loss)	1.2	(2.1)	9.0	(41.3)
Net income (loss) attributable to noncontrolling interests	1.1	(0.2)	(0.8)	(0.3)
Net income attributable to preferred shares dividends of a subsidiary company	3.1	3.2	6.3	6.4
Net income (loss) attributable to Atlantic Power Corporation	$ (3.0)	$ (5.1)	$ 3.5	$ (47.4)
Basic earnings (loss) per share: (Note 10)				

Income (loss) from continuing operations attributable to Atlantic Power Corporation	$	(0.02)	$	(0.21)	$	0.03	$	(0.69)
Income (loss) from discontinued operations, net of tax		(0.01)		0.17		0.00		0.27
Net income (loss) attributable to Atlantic Power Corporation	$	(0.03)	$	(0.04)	$	0.03	$	(0.42)
Diluted earnings (loss) per share: (Note 10)								
Income (loss) from continuing operations attributable to Atlantic Power Corporation	$	(0.02)	$	(0.21)	$	0.03	$	(0.69)
Income (loss) from discontinued operations, net of tax		(0.01)		0.17		0.00		0.27
Net income (loss) attributable to Atlantic Power Corporation	$	(0.03)	$	(0.04)	$	0.03	$	(0.42)
Weighted average number of common shares outstanding: (Note 10)								
Basic		119.9		113.7		119.7		113.6
Diluted		119.9		113.7		120.3		113.6

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,	
	2013	**2012**
Net income (loss)	$ 1.2	$ (2.1)
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedging activities	$ 0.6	$ (0.5)
Net amount reclassified to earnings	0.1	0.2
Net unrealized gain (loss) on derivatives	0.7	(0.3)
Foreign currency translation adjustments	(18.0)	(13.9)
Other comprehensive loss, net of tax	(17.3)	(14.2)
Comprehensive loss	(16.1)	(16.3)
Less: Comprehensive income attributable to noncontrolling interest	4.2	3.0
Comprehensive loss attributable to Atlantic Power Corporation	$ (20.3)	$ (19.3)

	Six months ended June 30,	
	2013	**2012**
Net income (loss)	$ 9.0	$ (41.3)
Other comprehensive income (loss), net of tax:		
Unrealized gain (loss) on hedging activities	$ 0.6	$ (0.5)
Net amount reclassified to earnings	0.4	0.5
Net unrealized gain on derivatives	1.0	
Foreign currency translation adjustments	(30.1)	3.3
Other comprehensive (loss) income, net of tax	(29.1)	3.3
Comprehensive loss	(20.1)	(38.0)
Less: Comprehensive income attributable to noncontrolling interest	5.5	6.1
Comprehensive loss attributable to Atlantic Power Corporation	$ (25.6)	$ (44.1)

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,	
	2013	**2012**
Cash flows from operating activities:		
Net income (loss)	$ 9.0	$ (41.3)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	92.8	76.8
Loss of discontinued operations	32.8	
Gain on sale of assets & other charges	(4.4)	
Long-term incentive plan expense	1.2	1.5
Impairment charges	4.9	3.0
Gain on sale of equity investments		(0.6)
Equity in earnings from unconsolidated affiliates	(15.9)	(10.8)
Distributions from unconsolidated affiliates	18.0	8.7
Unrealized foreign exchange (gain) loss	(8.7)	11.8
Change in fair value of derivative instruments	(47.7)	58.2
Change in deferred income taxes	(6.5)	(26.0)
Change in other operating balances		
Accounts receivable	(3.6)	20.3
Inventory	(1.3)	(4.3)
Prepayments, refundable income taxes and other assets	46.3	(9.8)
Accounts payable	(9.4)	(0.4)
Accruals and other liabilities	(10.6)	2.2
Cash provided by operating activities	96.9	89.3
Cash flows provided by (used in) investing activities:		
Change in restricted cash	(19.4)	2.3
Proceeds from sale of assets, net	148.3	
Proceeds from sale of equity investments		24.2
Cash paid for equity investment		(0.3)
Proceeds from treasury grant	53.7	
Biomass development costs	(0.1)	(0.2)
Construction in progress	(26.2)	(230.2)
Purchase of property, plant and equipment	(5.0)	(0.8)
Cash provided by (used in) investing activities	151.3	(205.0)
Cash flows (used in) provided by financing activities:		
Proceeds from project-level debt	20.8	255.3
Repayment of project-level debt	(64.2)	(9.3)
Offering costs related to tax equity	(1.0)	
Payments for revolving credit facility borrowings	(67.0)	(60.8)
Proceeds from revolving credit facility borrowings		22.8
Equity contribution from noncontrolling interest	44.6	
Deferred financing costs		(18.9)
Dividends paid	(52.5)	(71.4)
Cash (used in) provided by financing activities	(119.3)	117.7

Net increase in cash and cash equivalents		128.9		2.0
Cash and cash equivalents at beginning of period at discontinued operations		6.5		
Cash and cash equivalents at beginning of period		60.2		60.7
Cash and cash equivalents at end of period	$	195.6	$	62.7
Supplemental cash flow information				
Interest paid	$	65.3	$	58.2
Income taxes paid, net	$	1.4	$	1.5
Accruals for construction in progress	$	8.6	$	25.5

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of presentation and summary of significant accounting policies

General

Atlantic Power owns and operates a diverse fleet of power generation and infrastructure 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, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 3,018 megawatts ("MW") in which our aggregate ownership interest is approximately 2,098 MW. These totals exclude our 17.1% interest in Gregory Power Partners, L.P. ("Gregory") which was sold August 7, 2013 and our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012. Our current portfolio of continuing operations consists of interests in twenty-nine operational power generation projects across eleven states in the United States and two provinces in Canada. Piedmont Green Power project ("Piedmont"), our 53 MW biomass project in Georgia, achieved commercial operations in April 2013. In December 2012, we acquired a wind and solar development company, Ridgeline Energy Holdings, Inc. ("Ridgeline"), located in Seattle, Washington, which has enhanced our ability to develop, construct, and operate wind and solar energy projects across the United States and Canada. We also own a majority interest in Rollcast Energy Inc. ("Rollcast"), a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly 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.

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, 2012. 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, 2013, the results of operations and

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

comprehensive income (loss) for the three and six months ended June 30, 2013 and 2012, and our cash flows for the six months ended June 30, 2013 and 2012. In the opinion of management, all adjustments (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, 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 valuation of shares associated with our Long-Term Incentive Plan ("LTIP") and the fair value of financial instruments and derivatives. 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, 2012. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Recently issued accounting standards

Adopted

In July 2012, the Financial Accounting Standards Board ("FASB") issued changes to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. These changes became effective for us for any indefinite-lived intangible asset impairment test performed on January 1, 2013 or later. The adoption of these changes did not impact the consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to conform existing guidance regarding fair value measurement and disclosure between U.S generally accepted accounting principles

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

("GAAP") and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on the consolidated financial statements.

In December 2011, the FASB issued changes to the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The enhanced disclosures will enable users of an entity's financial statements to understand and evaluate the effect or potential effect of master netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. These changes became effective for us on January 1, 2013. Other than the additional disclosure requirements, the adoption of these changes did not impact 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. These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. For other amounts that are not required to be reclassified in their entirety to net income 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. Other than the additional disclosure requirements (see below), the adoption of these changes had no impact on the consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

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

	Three months ended June 30,	
	2013	**2012**
Foreign currency translation		
Balance at beginning of period	$ 0.6	$ 13.8
Other comprehensive loss:		
Foreign currency translation adjustments(1)	(18.0)	(13.9)
Balance at end of period	$ (17.4)	$ (0.1)
Cash flow hedges		
Balance at beginning of period	$ (1.1)	$ (1.1)
Other comprehensive loss:		
Net change from periodic revaluations	1.0	(0.8)
Tax (expense) benefit	(0.4)	0.3
Total Other comprehensive income (loss) before reclassifications, net of tax	0.6	(0.5)
Net amount reclassified to earnings:		
Interest rate swaps(2)	0.4	0.3
Fuel commodity swaps(3)	(0.1)	
Sub-total	0.3	0.3
Tax benefit(4)	0.2	0.1
Total amount reclassified from Accumulated other comprehensive loss, net of tax(5)	0.1	0.2
Total Other comprehensive income (loss)	0.7	(0.3)
Balance at end of period	$ (0.4)	$ (1.4)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

	Six months ended June 30, 2013	Six months ended June 30, 2012
Foreign currency translation		
Balance at beginning of period	$ 12.7	$ (3.4)
Other comprehensive loss:		
Foreign currency translation adjustments[1]	(30.1)	3.3
Balance at end of period	$ (17.4)	$ (0.1)
Cash flow hedges		
Balance at beginning of period	$ (1.4)	$ (1.4)
Other comprehensive loss:		
Net change from periodic revaluations	1.0	(0.8)
Tax (expense) benefit	(0.4)	0.3
Total Other comprehensive income (loss) before reclassifications, net of tax	0.6	(0.5)
Net amount reclassified to earnings:		
Interest rate swaps[2]	0.8	0.8
Fuel commodity swaps[3]	(0.2)	
Sub-total	0.6	0.8
Tax benefit[4]	0.2	0.3
Total amount reclassified from Accumulated other comprehensive loss, net of tax[5]	0.4	0.5
Total Other comprehensive income	1.0	
Balance at end of period	$ (0.4)	$ (1.4)

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

(2) This amount was included in Interest, net on the accompanying Statement of Consolidated Operations.

(3) These amounts were included in Fuel on the accompanying Statement of Consolidated Operations.

(4) These amounts were included in Income tax expense (benefit) on the accompanying Statement of Consolidated Operations.

(5) A positive amount indicates a corresponding charge to earnings and a negative amount indicates a corresponding benefit to earnings. These amounts were reflected on the accompanying Statement of Consolidated Operations in the line items indicated in footnotes 1 through 4.

Issued

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

litigation and judicial rulings. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

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 into net income 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 become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

2. Acquisitions and divestments

2012 Acquisitions

(a) Canadian Hills

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and our wholly owned subsidiary, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 300 MW wind energy project in the state of Oklahoma.

On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. We also closed a $310 million non-recourse, project-level construction financing facility for the project, which included a $290 million construction loan and a $20 million 5-year letter of credit facility. In July 2012 we funded approximately $190 million of our equity contribution (net of financing costs). In December 2012, the project received tax equity investments in aggregate of $225 million from a consortium of four institutional tax equity investors along with an approximately $44 million tax equity investment of our own. The project's outstanding construction loan was repaid by the proceeds from these tax equity investments, decreasing the project's short-term debt by $265 million as of December 31, 2012. Canadian Hills has no debt at June 30, 2013. On May 2, 2013, we syndicated our $44 million tax equity investment in Canadian Hills to an institutional investor and received net cash proceeds of $42.1 million. The syndication of our interest completes the sale of 100% of Canadian Hills' $269 million of tax equity interests. The cash proceeds will be held for general corporate purposes.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestments (Continued)

We own 99% of the project and consolidate it in our consolidated financial statements. Income attributable to the tax equity investors is classified as noncontrolling interests and is allocated utilizing the hypothetical liquidation book value method ("HLBV").

2013 Divestments

(a) Gregory

On April 2, 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 million of these proceeds will be held in escrow for up to one year after the closing date. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Gregory closed August 7, 2013 resulting in a gain on sale of approximately $31 million that will be recorded in the three months ended September 30, 2013.

(b) Path 15

On March 11, 2013 we entered into a purchase and sale agreement with Duke-American Transmission Company, a joint venture between 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 will be 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 an asset held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013 and 2012. See Note 11, *Assets held for sale and discontinued operations*, for further information.

(c) Auburndale, Lake and Pasco

On January 30, 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 million, including working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117 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 million received at closing and cash distributions from the Florida Projects of approximately $25 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 on the closing date. The remaining cash proceeds will be used for general corporate purposes. The Florida Projects were accounted for as assets held for sale in the consolidated balance sheets at December 31, 2012 and are a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013 and 2012. See Note 11, *Assets held for sale and discontinued operations*, for further information.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestments (Continued)

2012 Divestments

(d)
Primary Energy Recycling Corporation

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("Primary Energy" or "PERC"), whereby PERC agreed to purchase our 7,462,830.33 common membership interests in Primary Energy Recycling Holdings, LLC ("PERH") (14.3% of PERH total interests) for approximately $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million. The transaction closed in May 2012 and we recorded a $0.6 million gain on sale of our equity investment.

3. Equity method investments

The following summarizes the operating results for the three and six months ended June 30, 2013 and 2012, respectively, for earnings in our equity method investments:

	Three months ended June 30,		Six months ended June 30,	
(in millions)	**2013**	**2012**	**2013**	**2012**
Project revenue				
Chambers	$ 13.4	$ 14.7	$ 26.6	$ 28.0
Other	41.2	38.8	80.6	78.9
	54.6	53.5	107.2	106.9
Project expenses				
Chambers	11.1	8.7	20.7	18.5
Other	34.5	36.6	68.1	72.3
	45.6	45.3	88.8	90.8
Project other expenses				
Chambers	(0.6)	(0.4)	(1.2)	(1.6)
Other	0.3	(2.3)	(1.3)	(6.1)
	(0.3)	(2.7)	(2.5)	(7.7)
Project income				
Chambers	1.7	5.6	4.7	7.9
Other	7.0	(0.1)	11.2	0.5
	8.7	5.5	15.9	8.4

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Goodwill

Our goodwill balance was $331.2 million and $334.7 million as of June 30, 2013 and December 31, 2012, respectively. We recorded $331.1 million of goodwill in connection with the acquisition of Capital Power Income L.P. (the "Partnership") in 2011 and $3.5 million associated with the step-up acquisition of Rollcast in March 2010. 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. Subsequent to the three months ended June 30, 2013, based on a prolonged decline in our market capitalization and initiatives started at reducing our development and administrative expenses, we determined that it was appropriate to initiate a test of goodwill 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 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, 2013.

During the three months ended June 30, 2013, we recorded a $3.5 million impairment of goodwill at Rollcast which is a component of our Un-allocated corporate segment. We determined, based on the results of the two-step process, that the carrying amount of goodwill exceeded the implied fair value of goodwill. We also wrote-off $1.4 million of capitalized development costs at Rollcast related to the Greenway development project. The determination to impair goodwill and write-off the capitalized development costs was based on the reduced expectation of the Greenway project being further developed. The following table is a rollforward of goodwill for the six months ended June 30, 2013:

(in millions)	Northeast	Northwest	Southwest	Un-allocated corporate	Total
Balance at December 31, 2012	$ 135.3	$ 138.3	$ 57.6	$ 3.5	$ 334.7
Impairment of Goodwill				(3.5)	(3.5)
Balance at June 30, 2013	$ 135.3	$ 138.3	$ 57.6	$	$ 331.2

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Long-term debt

Long-term debt consists of the following:

(in millions)	June 30, 2013	December 31, 2012	Interest Rate
Recourse Debt:			
Senior unsecured notes, due 2018	$ 460.0	$ 460.0	9.0%
Senior unsecured notes, due June 2036 (Cdn$210.0)	199.7	211.1	6.0%
Senior unsecured notes, due July 2014	190.0	190.0	5.9%
Series A senior unsecured notes, due August 2015	150.0	150.0	5.9%
Series B senior unsecured notes, due August 2017	75.0	75.0	6.0%
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	32.0	33.5	7.4%
Cadillac term loan, due 2025	36.6	37.8	6.0% 8.0%
Piedmont construction loan, due 2013	126.1(1)	127.4	Libor plus 3.5%
Meadow Creek term loan, due 2024	171.4(2)	208.7	5.1% 5.6%
Rockland term loan, due 2027	85.8	86.5	6.4% 6.7%
Other long-term debt	1.1	0.3	5.5% 6.7%
Less: current maturities	(65.7)	(121.2)	
Total long-term debt	$ 1,462.0	$ 1,459.1	

Current maturities consist of the following:

	June 30, 2013	December 31, 2012	Interest Rate
Current Maturities:			
Epsilon Power Partners term facility, due 2019	$ 4.0	$ 3.0	7.4%
Cadillac term loan, due 2025	2.2	2.4	6.0% 8.0%
Piedmont construction loan, due 2013	53.9(1)	55.1	Libor plus 3.5%
Meadow Creek term loan, due 2024	4.1(2)	59.5	5.1% 5.6%
Rockland term loan, due 2027	1.4	1.2	6.4% 6.7%
Other current maturities	0.1		5.5% 6.7%
Total current maturities	$ 65.7	$ 121.2	

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(1) The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan and an $82.0 million construction loan that is expected to convert to a term loan in the third quarter of 2013. On April 19, 2013, Piedmont achieved commercial operations and submitted an application under the 1603 federal grant program to recover approximately 30% of its capital cost. The grant application was approved and we received a $49.5 million grant from the U.S. Treasury in July 2013. Upon receipt of the grant, we repaid in full the $51.0 million bridge loan with the proceeds of the grant and a $1.5 million contribution from Atlantic Power to cover the shortfall resulting from the federal sequester on spending. We expect to commence the repayment of the $82.0 million term loan in 2013.

(2) Meadow Creek debt consists of $172.8 million term loan and a $56.5 million cash grant loan. The cash grant loan was repaid in April 2013 with $49.0 million of proceeds from the 1603 grant with the U.S. Treasury, $4.7 million from the former owners to cover the shortfall resulting from the federal sequester on spending and a $2.8 million contribution from us to cover the shortfall from lower grant-eligible costs, primarily as a result of a lower project cost versus budget.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Long-term debt (Continued)

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.

Senior Credit Facility

At June 30, 2013, we had a senior credit facility of $300.0 million on a senior secured basis (the "senior credit facility"), $200.0 million of which could have been utilized for letters of credit. At June 30, 2013, the senior credit facility was undrawn and the applicable margin was 2.75%. At June 30, 2013, $82.5 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects.

On August 2, 2013 we entered into an amendment to our senior credit facility with our lenders (the "amended credit facility"). The most significant changes to the senior credit facility include the following:

- a decrease in capacity from $300 million to $150 million, all of which may be utilized for letters of credit (as compared to the previous $200 million that could have been utilized for letters of credit) and a sublimit of $25 million which may be utilized for other borrowings.

- a requirement to cash collateralize outstanding letters of credit in an amount equal to the excess above $125 million if the aggregate amount of letters of credit and borrowings outstanding under the amended credit facility exceeds $125 million;

- a requirement to maintain at all times unrestricted cash and cash equivalents of at least $75 million (inclusive of any cash collateral provided as described above), which shall be pledged to the lenders as security for the amended credit facility;

- an amendment to the maximum permissible Consolidated Total Net Debt to Consolidated EBITDA (each as defined in the amended credit facility) to 7.75 to 1.00 (as compared to a prior ratio of 7.50 to 1.00 declining to 7.00 to 1.00 over time);

- an amendment to the minimum permissible Consolidated EBITDA to Consolidated Interest Expense (each as defined in the amended credit facility) ratio to 1.60 to 1.00 (as compared to a prior ratio of 2.25 to 1.00);

- a requirement to pay a commitment fee of between 0.75% and 1.75% per year based on a percentage of the amount committed under the amended credit facility, which fee varies based on our unsecured debt rating (currently, the applicable commitment fee is 1.50%); and

- an amendment to the maturity date from November 4, 2015 to March 4, 2015.

Among other restrictions set forth in the amended credit facility, we are restricted from paying cash dividends to our shareholders if we do not comply with the financial covenants specified above. The amended credit facility is secured by pledges of certain assets and interests in certain subsidiaries. The senior credit facility contained customary representations, warranties, terms and conditions, and

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Long-term debt (Continued)

covenants, certain of which were amended in the amended credit facility. The amended covenants limit our ability to, among other things, incur additional indebtedness, merge or consolidate with others, make acquisitions, change our business and sell or dispose of assets. These amended covenants also include limitations on investments, limitations on dividends and other restricted payments, limitations on entering into certain types of restrictive agreements, limitations on transactions with affiliates and limitations on the use of proceeds from the amended credit facility. Specifically, under the amended credit facility, we are only permitted to make voluntary prepayments or repurchases of the $150 million in principal amount of 5.87% Senior Guaranteed Notes, Series A, due August 15, 2015 that were issued by our subsidiary Atlantic Power (US) G.P., except that under the amended credit facility we may also voluntarily prepay or repurchase any of our outstanding debt (including for these purposes subsidiary debt guaranteed by us) from the proceeds of debt permitted to be incurred to refinance that outstanding debt or during the 60-day period preceding the maturity of that outstanding debt. Under the senior credit facility, we had the right generally to repurchase substantially more of our outstanding debt issuances, subject to the satisfaction of certain conditions. Under the amended credit facility, the lenders also consented to (i) our previously announced sale of Delta-Person and (ii) the sale of AP Onondaga, LLC, Onondaga Renewables, LLC and their property.

Borrowings under the amended credit facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the US Prime Rate, the Eurocurrency LIBOR Rate or the Cdn. Prime Rate (each as defined in the amended credit facility), as applicable, plus a margin of between 1.75% and 4.75% that varies based on our unsecured debt rating. Currently, the applicable margin for loans bearing interest at the Eurocurrency LIBOR Rate and for outstanding letters of credit is 4.25%. The foregoing summary is qualified in its entirety by reference to the amended credit facility, which has been filed as an exhibit to our Current Report on Form 8-K on August 5, 2013.

6. 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, 2013 and December 31, 2012. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2013			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Cash and cash equivalents	$ 195.6	$	$	$ 195.6
Restricted cash	40.1			40.1
Derivative instruments asset		9.0		9.0
Total	$ 235.7	$ 9.0	$	$ 244.7
Liabilities:				
Derivative instruments liability	$	$ 114.2	$	$ 114.2
Total	$	$ 114.2	$	$ 114.2

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Fair value of financial instruments (Continued)

	December 31, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 60.2	$	$	$ 60.2
Restricted cash	28.6			28.6
Derivative instruments asset		20.6		20.6
Total	$ 88.8	$ 20.6	$	$ 109.4
Liabilities:				
Derivative instruments liability	$	$ 151.1	$	$ 151.1
Total	$	$ 151.1	$	$ 151.1

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. 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, 2013, the credit valuation adjustments resulted in a $12.0 million net increase in fair value, which consists of a $0.6 million pre-tax gain in other comprehensive income and an $11.4 million gain in change in fair value of derivative instruments. As of December 31, 2012, the credit valuation adjustments resulted in an $18.4 million net increase in fair value, which consists of a $1.0 million pre-tax gain in other comprehensive income, a $13.8 million gain in change in fair value of derivative instruments and a $3.6 million increase related to interest rate swaps assumed in the acquisition of Ridgeline.

7. 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. For certain contracts designated as cash flow hedges, 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. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

For derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings. The guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

Gas purchase agreements

On March 12, 2012, we discontinued the application of the normal purchase normal sales ("NPNS") exemption on gas purchase agreements at our North Bay, Kapuskasing and Nipigon projects. On that date, we entered into an agreement with a third party that resulted in the gas purchase agreements no longer qualifying for the NPNS exemption. The agreements at North Bay and Kapuskasing expire on December 31, 2016. These gas purchase agreements 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.

In May 2012, the Nipigon project entered into a long-term contract for the purchase of natural gas beginning on January 1, 2013 and expiring on December 31, 2022. This contract is accounted for as a derivative financial instrument and is recorded in the consolidated balance sheet at fair value at June 30, 2013 and December 31, 2012. Changes in the fair market value of the contract are recorded in the consolidated statements of operations.

In April and June 2013, the Tunis project entered into contracts for the purchase of natural gas beginning on November 1, 2013 and expiring on March 31, 2014. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value as of June 30, 2013. Changes in the fair market value of the contracts are recorded in the consolidated statement of operations.

Natural gas swaps

Our strategy to mitigate a portion of the 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 have entered into natural gas swaps to effectively fix the price of 3.2 million Mmbtu of future natural gas purchases, or approximately 74% of our share of the expected natural gas purchases at the project during 2014 and 2015. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 38% of our share of the expected natural gas purchases at the project during 2016 and 2017.

Interest rate swaps

Cadillac Renewable Energy, LLC ("Cadillac") has an interest rate swap agreement that effectively fixes the interest rate at 6.0% from February 16, 2011 to 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).

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

Piedmont 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 November 2017, the fixed rate of the swap is 4.5% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.5% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility that will convert to a term loan. 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. 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 ("Epsilon") has 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 7.4% and has a maturity date of July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon's debt. This interest rate swap agreement is not designated as a hedge and changes in its 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 notional amount due on the term loan commencing on December 30, 2011 and ending December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3% - 2.8%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2026 and ends on 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 converted 75% of the floating rate debt to a fixed interest rate of 2.3% plus an applicable margin of 2.8% - 3.3% from December 31, 2012 to 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.

Foreign currency forward contracts

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 and interest on corporate level long-term debt and convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

currency risk impact on future payments of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 71% of our expected dividend, long-term debt and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At June 30, 2013, the forward contracts consist of (1) monthly purchases through the end of July 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$34.9 million at an average exchange rate of Cdn$1.10 per U.S. dollar. It is our intention to periodically consider extending or terminating these forward contracts.

In April 2013, we terminated various foreign currency forward contracts with expiration dates through June 2015 assumed in our acquisition of the Partnership resulting in proceeds and a realized gain of $9.4 million.

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, 2013 and December 31, 2012:

	Units	June 30, 2013	December 31, 2012
Natural gas swaps	Natural Gas (Mmbtu)	5.6	10.6
Gas purchase agreements	Natural Gas (GJ)	46.1	49.8
Interest rate swaps	Interest (US$)	166.6	172.0
Foreign currency forwards	Cdn$	40.9	176.6

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

Fair value of derivative instruments

The fair value of our derivative assets and liabilities under counterparty master netting agreement are disclosed net on the consolidated balance sheets at June 30, 2013 and December 31, 2012. In the following table, 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, 2013	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.3
Interest rate swaps long-term		3.4
Total derivative instruments designated as cash flow hedges		4.7
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		7.2
Interest rate swaps long-term	7.3	12.9
Foreign currency forward contracts current	0.9	0.3
Foreign currency forward contracts long-term	1.3	0.3
Natural gas swaps current		0.7
Natural gas swaps long-term		3.8
Gas purchase agreements current		23.0
Gas purchase agreements long-term		62.0
Total derivative instruments not designated as cash flow hedges	9.5	110.2
Total derivative instruments	$ 9.5	$ 114.9

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

	December 31, 2012 Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.3
Interest rate swaps long-term		5.2
Total derivative instruments designated as cash flow hedges		6.5
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		7.3
Interest rate swaps long-term	0.1	27.7
Foreign currency forward contracts current	9.5	
Foreign currency forward contracts long-term	11.0	
Natural gas swaps current		
Natural gas swaps long-term	0.1	3.9
Gas purchase agreements current	0.1	24.5
Gas purchase agreements long-term		81.4
Total derivative instruments not designated as cash flow hedges	20.8	144.8
Total derivative instruments	$ 20.8	$ 151.3

Accumulated other comprehensive income

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

(in millions) 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)

Three months ended June 30, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2012	$ (1.4)	$ 0.3	$ (1.1)
Change in fair value of cash flow hedges	(0.5)		(0.5)
Realized from OCI during the period	0.2		0.2

Accumulated OCI balance at June 30, 2012	$ (1.7)	$ 0.3	$ (1.4)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Derivative instruments and hedging activities (Continued)

Six months ended June 30, 2013	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2012	$ (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)

Six months ended June 30, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2011	$ (1.7)	$ 0.3	$ (1.4)
Change in fair value of cash flow hedges	(0.5)		(0.5)
Realized from OCI during the period	0.5		0.5
Accumulated OCI balance at June 30, 2012	$ (1.7)	$ 0.3	$ (1.4)

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,	
		2013	2012
Gas purchase agreements	Fuel	$ 14.1	$ 13.2
Foreign currency forwards	Foreign exchange gain	(10.8)	(3.1)
Interest rate swaps	Interest, net	4.0	1.1

	Classification of (gain) loss recognized in income	Six months ended June 30,	
		2013	2012
Gas purchase agreements	Fuel	$ 30.4	$ 16.0
Foreign currency forwards	Foreign exchange gain	(13.3)	(15.0)
Interest rate swaps	Interest, net	6.6	2.2

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. 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, 2013	Three months ended June 30, 2012
Natural gas swaps	Change in fair value of derivatives	$ 1.1	$ 0.5
Gas purchase agreements	Change in fair value of derivatives	(7.4)	1.2
Interest rate swaps	Change in fair value of derivatives	(18.0)	3.0
Total change in fair value of derivative instruments		$ (24.3)	$ 4.7
Foreign currency forwards	Foreign exchange loss	$ 12.8	$ 7.7

	Classification of (gain) loss recognized in income	Six months ended June 30, 2013	Six months ended June 30, 2012
Natural gas swaps	Change in fair value of derivatives	$ 0.7	$ 1.4
Gas purchase agreements	Change in fair value of derivatives	(15.5)	59.1
Interest rate swaps	Change in fair value of derivatives	(22.1)	1.5
Total change in fair value of derivative instruments		$ (36.9)	$ 62.0
Foreign currency forwards	Foreign exchange loss	$ 18.8	$ 12.9

8. Income taxes

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.

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Current income tax expense	$ 3.4	$ 3.0	$ 5.4	$ 3.8
Deferred tax benefit	(2.8)	(8.3)	(7.3)	(26.0)
Total income tax expense (benefit)	$ 0.6	$ (5.3)	$ (1.9)	$ (22.2)

As of June 30, 2013, we have recorded a valuation allowance of $ 127.1 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Income taxes (Continued)

tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

9. Employee incentive programs

Long-Term Incentive Program

The following table summarizes the changes in LTIP notional units during the six months ended June 30, 2013:

(Units in thousands)	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2012	492,535	$ 13.9
Granted	587,201	4.9
Additional shares from dividends	27,151	10.0
Forfeited	(42,000)	12.3
Vested	(202,696)	13.5
Outstanding at June 30, 2013	862,191	$ 7.8

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 2013 is recorded net of estimated forfeitures. See Note 14 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2012 for further details. Cash payments made for vested notional units for the six months ended June 30, 2013 was $0.9 million. Compensation expense for LTIP was $0.8 million and $1.2 million for the three and six months end June 30, 2013, respectively.

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of June 30, 2013 and December 31, 2012:

	June 30, 2013	December 31, 2012
Weighted average risk free rate of return	0.1 0.6%	0.1 0.3%
Dividend yield	9.7%	10.1%
Expected volatility Atlantic Power	37.9 62.1%	22.5%
Expected volatility peer companies	14.7 82.7%	11.9 97.1%
Weighted average remaining measurement period	2.2 years	1.4 years

10. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share are calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share are 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Basic and diluted earnings (loss) per share (Continued)

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 and potentially dilutive shares utilized in the per share calculation for the three and six months ended June 30, 2013 and 2012:

	Three months ended June 30,		Six months ended June 30,	
	2013	2012	2013	2012
Numerator:				
Income (loss) from continuing operations attributable to Atlantic Power Corporation	$ (2.3)	$ (24.4)	$ 3.3	$ (78.3)
Income (loss) from discontinued operations, net of tax	(0.7)	19.3	0.2	30.9
Net income (loss) attributable to Atlantic Power Corporation	$ (3.0)	$ (5.1)	$ 3.5	$ (47.4)
Denominator:				
Weighted average basic shares outstanding	119.9	113.7	119.7	113.6
Dilutive potential shares:				
Convertible debentures	27.7	13.3	27.7	13.3
LTIP notional units	0.8	0.5	0.6	0.5
Potentially dilutive shares	148.4	127.5	148.0	127.4
Diluted earnings (loss) per share from continuing operations attributable to Atlantic Power Corporation	$ (0.02)	$ (0.21)	$ 0.03	$ (0.69)
Diluted earnings (loss) per share from discontinued operations	(0.01)	0.17	0.00	0.27
Diluted earnings (loss) per share attributable to Atlantic Power Corporation	$ (0.03)	$ (0.04)	$ 0.03	$ (0.42)

Potentially dilutive shares from convertible debentures and LTIP notional units have been excluded from fully diluted shares for the three months ended June 30, 2013 and the three and six months ended June 30, 2012 because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures have been excluded from fully diluted shares for the six months ended June 30, 2013 because their impact would be anti-dilutive.

11. Assets held for sale and discontinued operations

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 and 2012.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Assets held for sale and discontinued operations (Continued)

The following tables summarize the revenue, income (loss) from operations, and income tax expense of Path 15, Auburndale, Lake, and Pasco for the three and six months ended June 30, 2013 and 2012:

(in millions)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Revenue	$ 8.4	$ 53.8	$ 71.6	$ 102.7
Income (loss) from operations of discontinued businesses	(0.3)	19.1	1.0	31.3
Income tax expense (benefit)	0.4	(0.2)	0.8	0.4
Income (loss) from operations of discontinued businesses, net of tax	$ (0.7)	$ 19.3	$ 0.2	$ 30.9

Basic and diluted earnings (loss) per share related to income from discontinued operations for the Florida Projects and Path 15 were $(0.01) and $0.17 for the three month periods ended June 30, 2013 and 2012, respectively, and $0.00 and $0.27 for the six month periods ended June 30, 2013 and 2012, respectively.

The assets and liabilities of these projects classified as assets held for sale in the accompanying consolidated balance sheets as of December 31, 2012 consisted of the following:

(in millions)	December 31, 2012
Current assets:	
Cash and cash equivalents	$ 6.5
Restricted cash	12.6
Accounts receivable	21.9
Other current assets	6.3
	47.3
Non-current assets:	
Property, plant & equipment	111.9
Transmission system rights	172.4
Goodwill	8.9
Other assets	10.9
Assets from discontinued operations	351.4
Current liabilities:	
Accounts payable and other accrued liabilities	$ 16.5
Current portion of long-term debt	14.3
Current portion of derivative instruments liability	20.0
Other liabilities	0.5
	51.3
Long-term liabilities	
Long-term debt	137.7
Other long-term liabilities	
Liabilities from discontinued operations	189.0

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Equity

The following table provides a reconciliation of the beginning and ending equity attributable to shareholders of Atlantic Power, preferred shares issued by a subsidiary company, noncontrolling interests and total equity for the six months ended June 30, 2013 and 2012:

	Six months ended June 30, 2013			
(in millions)	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 loss 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 interst			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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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Equity (Continued)

	Six months ended June 30, 2012			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 891.5	$ 221.3	$ 3.0	$ 1,115.8
Net income (loss)	(47.4)	6.4	(0.3)	(41.3)
Realized and unrealized loss on hedging activities, net of tax	(0.1)			(0.1)
Foreign currency translation adjustment, net of tax	3.3			3.3
Common shares issued for LTIP	1.0			1.0
Dividends declared on common shares	(64.8)			(64.8)
Dividends declared on preferred shares of a subsidiary company		(6.4)		(6.4)
Balance at June 30	$ 783.5	$ 221.3	$ 2.7	$ 1,007.5

13. Segment and geographic information

Our operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Our segments align with management's resource allocation and assessment of performance and reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant in the United States and Canada. Un-allocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel and Ridgeline, which develops and operates wind and solar power projects. These costs are not allocated to the operating segments when determining segment profit or loss.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income 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. Path 15, a component of the Southwest segment, and the Auburndale, Lake and Pasco projects, which are components of the Southeast segment, are included in the income from discontinued operations line item in the table below. We have adjusted prior periods

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

to reflect this reclassification. A reconciliation of project income to Project Adjusted EBITDA is included in the tables below.

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three months ended June 30, 2013						
Project revenues	$ 52.8	$ 6.2	$ 21.3	$ 58.7	$	$ 139.0
Segment assets	1,144.1	229.6	1,118.9	939.5	135.3	3,567.4
Project Adjusted EBITDA	$ 26.0	$ 2.4	$ 12.3	$ 19.0	$ (3.5)	56.2
Change in fair value of derivative instruments	(8.3)	(2.3)	(15.3)		(0.9)	(26.8)
Depreciation and amortization	17.8	3.0	14.8	14.8	0.2	50.6
Interest, net	4.3	1.2	4.7	0.3	(1.0)	9.5
Other project expense	0.5	0.1			6.7	7.3
Project income (loss)	11.7	0.4	8.1	3.9	(8.5)	15.6
Administration					11.8	11.8
Interest, net					25.3	25.3
Foreign exchange gain					(14.5)	(14.5)
Other expense, net					(9.5)	(9.5)
Income (loss) from continuing operations before income taxes	11.7	0.4	8.1	3.9	(21.6)	2.5
Income tax expense					0.6	0.6
Net income (loss) from continuing operations	11.7	0.4	8.1	3.9	(22.2)	1.9
Income (loss) from discontinued operations		(1.4)		0.7		(0.7)
Net income (loss)	$ 11.7	$ (1.0)	$ 8.1	$ 4.6	$ (22.2)	$ 1.2

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three months ended June 30, 2012						
Project revenues	$ 45.9	$	$ 16.7	$ 38.2	$ 0.6	$ 101.4
Segment assets	1,180.0	434.3	784.2	987.7	42.4	3,428.6
Project Adjusted EBITDA	$ 22.4	$ 2.1	$ 12.4	$ 12.6	$ (4.1)	$ 45.4
Change in fair value of derivative instruments	(1.6)	3.7				2.1
Depreciation and amortization	20.2	1.4	10.6	9.1		41.3
Interest, net	4.7		1.5	0.3	(0.1)	6.4
Other project expense	0.3			2.7	0.1	3.1
Project income (loss)	(1.2)	(3.0)	0.3	0.5	(4.1)	(7.5)
Administration					8.0	8.0
Interest, net					21.4	21.4
Foreign exchange gain					(4.2)	(4.2)
Other expense, net					(6.0)	(6.0)
Income (loss) from continuing operations before income taxes	(1.2)	(3.0)	0.3	0.5	(23.3)	(26.7)
Income tax benefit					(5.3)	(5.3)
Net income (loss) from continuing operations	(1.2)	(3.0)	0.3	0.5	(18.0)	(21.4)
Income (loss) from discontinued operations		19.6		(0.3)		19.3
Net income (loss)	$ (1.2)	$ 16.6	$ 0.3	$ 0.2	$ (18.0)	$ (2.1)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Six months ended June 30, 2013						
Project revenues	$ 120.6	$ 6.2	$ 46.0	$ 106.7	$ (0.3)	$ 279.2
Segment assets	1,144.1	229.6	1,118.9	939.5	135.3	3,567.4
Project Adjusted EBITDA	$ 71.9	$ 4.5	$ 33.6	$ 35.0	$ (8.2)	136.8
Change in fair value of derivative instruments	(16.4)	(3.6)	(18.3)			(38.3)
Depreciation and amortization	37.9	4.5	30.6	29.8	0.2	103.0
Interest, net	8.7	1.2	9.4	0.5	(0.8)	19.0
Other project expense	0.9	0.1			5.4	6.4
Project income (loss)	40.8	2.3	11.9	4.7	(13.0)	46.7
Administration					20.1	20.1
Interest, net					51.2	51.2
Foreign exchange gain					(22.0)	(22.0)
Other expense, net					(9.5)	(9.5)
Income (loss) from continuing operations before income taxes	40.8	2.3	11.9	4.7	(52.8)	6.9
Income tax benefit					(1.9)	(1.9)
Net income (loss) from continuing operations	40.8	2.3	11.9	4.7	(50.9)	8.8
Income (loss) from discontinued operations		(1.1)		1.3		0.2
Net income (loss)	$ 40.8	$ 1.2	$ 11.9	$ 6.0	$ (50.9)	$ 9.0

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Six months ended June 30, 2012						
Project revenues	$ 112.8	$	$ 32.0	$ 73.7	$ 1.6	$ 220.1
Segment assets	1,180.0	434.3	784.2	987.7	42.4	3,428.6
Project Adjusted EBITDA	$ 64.8	$ 4.2	$ 25.9	$ 24.7	$ (7.7)	$ 111.9
Change in fair value of derivative instruments	56.4	3.2				59.6
Depreciation and amortization	37.7	2.8	21.0	19.6		81.1
Interest, net	9.4		2.7	0.3		12.4
Other project expense	0.5			2.8		3.3
Project income (loss)	(39.2)	(1.8)	2.2	2.0	(7.7)	(44.5)
Administration					15.7	15.7
Interest, net					43.4	43.4
Foreign exchange gain					(3.2)	(3.2)
Other expense, net					(6.0)	(6.0)
Income (loss) from continuing operations before income taxes	(39.2)	(1.8)	2.2	2.0	(57.6)	(94.4)
Income tax benefit					(22.2)	(22.2)
Net income (loss) from continuing operations	(39.2)	(1.8)	2.2	2.0	(35.4)	(72.2)
Income from discontinued operations		30.2		0.7		30.9
Net income (loss)	$ (39.2)	$ 28.4	$ 2.2	$ 2.7	$ (35.4)	$ (41.3)

The tables below provide information, by country, about our consolidated operations. 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	
	2013	2012	2013	2012	June 30, 2013	December 31, 2012
United States	$ 93.9	$ 55.5	$ 166.7	$ 110.9	$ 1,428.3	$ 1,504.8
Canada	45.1	45.9	112.5	109.2	504.0	550.7
Total	$ 139.0	$ 101.4	$ 279.2	$ 220.1	$ 1,932.3	$ 2,055.5

The Ontario Electricity Financial Corp ("OEFC") and British Columbia Hydro and Power Authority ("BC Hydro") provided for approximately 22.2% and 10.1%, respectively, of total consolidated revenues for the three months ended June 30, 2013 and 29.1% and 11.1%, respectively, of total consolidated revenues for the six months ended June 30, 2013. OEFC and BC Hydro provided for approximately 28.7% and 16.4%, respectively, of total consolidated revenues for the three months ended June 30, 2012 and 34.9% and 14.5%, respectively, of total consolidated revenues for the six

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

months ended June 30, 2012. OEFC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the Northeast segment and BC Hydro purchases electricity from the Mamquam, Moresby Lake and Williams Lake projects in the Northwest segment.

14. Commitments and contingencies

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

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 "Individual Defendants," and together with Atlantic Power, the "Defendants") (the "U.S. 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 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 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. The next steps in the Ontario litigation will be directed toward determining which firms and plaintiff or plaintiffs will have carriage of the action. The District Court complaints differ in terms of the identities of the Individual Defendants they name, as noted above, the named plaintiffs, and the purported class period they allege (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 alleges, 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 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 Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. The allegations in the Canadian Actions are essentially the same as those asserted in the District Court actions.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Commitments and contingencies (Continued)

The parties to each District Court action have 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 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 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. The District Court has scheduled a hearing for August 9, 2013 to address, among other issues, the Lead Plaintiff Motions.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the five District Court actions. As of May 6, 2013, the plaintiffs have not specified an amount of alleged damages in the respective U.S. and Canadian Actions filed on March 19, 2013 and April 2, 2013 (including the related statement of claim filed on May 2, 2013), in which the plaintiffs have alleged damages of Cdn$1,100,000,000 and Cdn$208,500,000, respectively, plus interest and costs. However, 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 the litigation. Atlantic Power intends to defend vigorously against these actions.

Morris

On May 29, 2011, our Morris facility was struck by lightning. As a result, steam and electric deliveries were interrupted to our host Equistar Chemicals, LP. ("Equistar"). We believed the interruption constituted a force majeure under the energy services agreement with Equistar. Equistar disputed this interpretation and initiated arbitration proceedings under the relevant agreement for recovery of resulting lost profits and equipment damage among other items. The Equistar arbitration claim has now been fully resolved. The lost profits portion of the claim was dismissed by the Arbitration Panel and all claims for equipment damage were resolved by the parties and their insurers through mediation on April 11 and 12, 2013, and a definitive Settlement Agreement and Mutual Release was executed effective as of April 30, 2013.

Other

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, 2012.

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Commitments and contingencies (Continued)

reasonably estimated. With respect to such other matters arising in the normal course of business, 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, 2013.

15. Guarantees and condensed consolidating financial information

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 and improbable to occur. 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.

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 certain tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

As of June 30, 2013 and December 31, 2012, we had $460.0 million of Senior Notes. These notes are guaranteed by certain of our wholly owned subsidiaries, or guarantor subsidiaries. These guarantees are joint and several.

Unless otherwise noted below, each of the following 100% owned guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of June 30, 2013:

Atlantic Power Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, Atlantic Oklahoma Wind LLC, Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Atlantic Power Holdings, Inc,. Atlantic Power Services Canada GP Inc., Atlantic Power Services Canada LP, Atlantic Power Services, LLC, Atlantic Rockland Holdings, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Cadillac Holdings, LLC, Atlantic Idaho Wind Holdings, LLC, Atlantic Idaho Wind C, LLC, Baker Lake Hydro, LLC, Olympia Hydro, LLC, Teton East Coast Generation, LLC, Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, Atlantic Piedmont Holdings LLC, Teton Selkirk, LLC, Teton Operating Services, LLC, Atlantic Ridgeline Holdings, LLC, Ridgeline Energy Holdings, Inc., Ridgeline Energy LLC, Pah Rah Holding Company LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Eastern Energy LLC, Ridgeline Alternative Energy LLC, Frontier Solar LLC, Ridgeline Energy Solar LLC, Pah Rah Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC and Meadow Creek Intermediate Holdings LLC.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

The following condensed consolidating financial information presents the financial information of Atlantic Power, the guarantor subsidiaries, and Curtis Palmer, LLC ("Curtis Palmer") (our non-guarantor subsidiary) in accordance with Rule 3-10 under the SEC's Regulation S-X. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or Curtis Palmer operated as independent entities.

In this presentation, Atlantic Power consists of parent company operations. Guarantor subsidiaries of Atlantic Power are reported on a combined basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

June 30, 2013

(in millions of U.S. dollars)
(Unaudited)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Assets					
Current assets:					
Cash and cash equivalents	$ 195.6	$	$	$	$ 195.6
Restricted cash	40.1				40.1
Accounts receivable	151.9	23.9	3.0	(107.4)	71.4
Prepayments, supplies, and other current assets	36.9	1.2	1.4	(1.0)	38.5
Total current assets	424.5	25.1	4.4	(108.4)	345.6
Property, plant, and equipment, net	1,761.1	172.5		(1.3)	1,932.3
Equity investments in unconsolidated affiliates	3,706.5		973.9	(4,270.0)	410.4
Other intangible assets, net	331.3	152.3			483.6
Goodwill	273.0	58.2			331.2
Other assets	521.4		437.1	(894.2)	64.3
Total assets	$ 7,017.8	$ 408.1	$ 1,415.4	$ (5,273.9)	$ 3,567.4
Liabilities					
Current liabilities:					
Accounts payable and accrued liabilities	$ 97.5	$ 18.5	$ 68.7	$ (107.4)	$ 77.3
Revolving credit facility					
Current portion of long-term debt	65.7				65.7
Liabilities from discontinued operations					
Other current liabilities	36.3		3.8	(1.0)	39.1
Total current liabilities	199.5	18.5	72.5	(108.4)	182.1
Long-term debt	812.0	190.0	460.0		1,462.0
Convertible debentures	(0.1)		408.4		408.3
Other non-current liabilities	1,184.5	8.5	0.5	(844.6)	348.9
Total liabilities	2,195.9	217.0	941.4	(953.0)	2,401.3
Equity					
Common shares	4,302.9	191.1	1,285.3	(4,493.9)	1,285.4
Preferred shares issued by a subsidiary company	248.2			(26.9)	221.3
Accumulated other comprehensive income (loss)	(19.5)				(19.5)
Retained deficit	14.1		(811.3)	199.9	(597.3)

Total Atlantic Power Corporation shareholders' equity		4,545.7		191.1		474.0		(4,320.9)		889.9
Noncontrolling interest		276.2								276.2
Total equity		4,821.9		191.1		474.0		(4,320.9)		1,166.1
Total liabilities and equity	$	7,017.8	$	408.1	$	1,415.4	$	(5,273.9)	$	3,567.4

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended June 30, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 128.3	$ 10.8	$	$ (0.1)	$ 139.0
Project expenses:					
Fuel	52.0				52.0
Project operations and maintenance	47.6	(0.7)	0.2	(0.2)	46.9
Development	1.8				1.8
Depreciation and amortization	38.3	3.9			42.2
	139.7	3.2	0.2	(0.2)	142.9
Project other income (expense):					
Change in fair value of derivative instruments	24.3				24.3
Equity in earnings of unconsolidated affiliates	8.7				8.7
Interest expense, net	(5.9)	(2.8)			(8.7)
Other	(5.1)		0.3		(4.8)
	22.0	(2.8)	0.3		19.5
Project income	10.6	4.8	0.1	0.1	15.6
Administrative and other expenses (income):					
Administration expense	5.8		6.0		11.8
Interest, net	18.9		6.4		25.3
Foreign exchange gain	(5.5)		(9.0)		(14.5)
Other income	(9.5)				(9.5)
	9.7		3.4		13.1
Income (loss) from continuing operations before income taxes	0.9	4.8	(3.3)	0.1	2.5
Income tax expense	0.6				0.6
Net income (loss) from continuing operations	0.3	4.8	(3.3)	0.1	1.9
Net loss from discontinued operations	(0.7)				(0.7)
Net income (loss)	(0.4)	4.8	(3.3)	0.1	1.2
Net income attributable to noncontrolling interest	1.1			3.1	4.2
Net income (loss) attributable to Atlantic Power Corporation	$ (1.5)	$ 4.8	$ (3.3)	$ (3.0)	$ (3.0)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Six months ended June 30, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 259.9	$ 19.6	$	$ (0.3)	$ 279.2
Project expenses:					
Fuel	101.6				101.6
Project operations and maintenance	74.1	0.9	0.5	(0.3)	75.2
Development	3.5				3.5
Depreciation and amortization	75.8	7.7			83.5
	255.0	8.6	0.5	(0.3)	263.8
Project other income (expense):					
Change in fair value of derivative instruments	36.9				36.9
Equity in earnings of unconsolidated affiliates	15.9				15.9
Interest expense, net	(11.1)	(5.6)			(16.7)
Other	(5.1)		0.3		(4.8)
	36.6	(5.6)	0.3		31.3
Project income (loss)	41.5	5.4	(0.2)		46.7
Administrative and other expenses (income):					
Administration expense	10.4		9.7		20.1
Interest, net	38.2		13.0		51.2
Foreign exchange gain	(8.0)		(14.0)		(22.0)
Other income	(9.5)				(9.5)
	31.1		8.7		39.8
Income (loss) from continuing operations before income taxes	10.4	5.4	(8.9)		6.9
Income tax benefit	(1.9)				(1.9)
Net income (loss) from continuing operations	12.3	5.4	(8.9)		8.8
Net income from discontinued operations	0.2				0.2
Net income (loss)	12.5	5.4	(8.9)		9.0
Net income (loss) attributable to noncontrolling interest	(0.8)			6.3	5.5
Net income (loss) attributable to Atlantic Power Corporation	$ 13.3	$ 5.4	$ (8.9)	$ (6.3)	$ 3.5

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME

Three and six months ended June 30, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net income (loss)	$ (0.4)	$ 4.8	$ (3.3)	$ 0.1	$ 1.2
Other comprehensive income (loss):					
Unrealized gain on hedging activities	0.6				0.6
Net amount reclassified to earnings	0.1				0.1
Net unrealized gain on derivatives	0.7				0.7
Foreign currency translation adjustments	(18.0)				(18.0)
Other comprehensive loss, net of tax	(17.3)				(17.3)
Comprehensive income (loss)	(17.7)	4.8	(3.3)	0.1	(16.1)
Less: Comprehensive income attributable to noncontrolling interest	4.2				4.2
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ (21.9)	$ 4.8	$ (3.3)	$ 0.1	$ (20.3)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net income (loss)	$ 12.5	$ 5.4	$ (8.9)	$	$ 9.0
Other comprehensive income (loss):					
Unrealized gain on hedging activities	0.6				0.6
Net amount reclassified to earnings	0.4				0.4
Net unrealized gain on derivatives	1.0				1.0
Foreign currency translation adjustments	(30.1)				(30.1)
Other comprehensive loss, net of tax	(29.1)				(29.1)
Comprehensive income (loss)	(16.6)	5.4	(8.9)		(20.1)

Less: Comprehensive income attributable to noncontrolling interest	5.5				5.5
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ (22.1)	$ 5.4	$ (8.9)	$	$ (25.6)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Six months ended June 30, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net cash provided by operating activities	$ 45.6	$ 1.4	$ 49.9	$	$ 96.9
Cash flows provided by (used in) investing activities:					
Proceeds from treasury grant	53.7				53.7
Proceeds from sale of assets	148.3				148.3
Cash (paid) received from equity investment	5.5		(5.5)		
Change in restricted cash	(19.4)				(19.4)
Biomass development costs	(0.1)				(0.1)
Construction in progress	(26.2)				(26.2)
Purchase of property, plant and equipment	(3.6)	(1.4)			(5.0)
Net cash provided by (used in) investing activities	158.2	(1.4)	(5.5)		151.3
Cash flows provided by (used in) financing activities:					
Offering costs related to tax equity	(1.0)				(1.0)
Repayment of project-level debt	(64.2)				(64.2)
Proceeds from project-level debt	20.8				20.8
Payments for revolving credit facility borrowings	(47.0)		(20.0)		(67.0)
Equity investment from noncontrolling interest	42.7		1.9		44.6
Dividends paid	(9.3)		(43.2)		(52.5)
Net cash provided by (used in) financing activities	(58.0)		(61.3)		(119.3)
Net increase (decrease) in cash and cash equivalents	145.8		(16.9)		128.9
Cash and cash equivalents at beginning of period	49.8		16.9		66.7
Cash and cash equivalents at end of period	$ 195.6	$	$	$	$ 195.6

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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 amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due;
- the amount of cash proceeds expected to be received following the sale of our projects and the timing of such sales;
- the results of our goodwill impairment testing;
- our ability to meet the financial covenants under our amended credit facility and other indebtedness and the ability to maintain our dividend payments at the current level; 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 this Quarterly Report on Form 10-Q and in our Annual Report on Form 10-K for the year ended December 31, 2012. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- the expiration or termination of power purchase agreements;
- 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;
- projects not operating according to plan;
- the dependence of our projects on third-party suppliers;

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

the dependence of our windpower projects on suitable wind and associated conditions;

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

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

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- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- 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;
- construction risks;
- labor disruptions;
- our ability to retain, motivate and recruit executives and other key employees;
- unstable capital and credit markets;
- our indebtedness and financing arrangements;
- the impact on us of recent amendments to our senior credit facility;
- compliance with our senior credit facility and our ability to obtain requested waivers and/or amendments;
- the impact of compliance with covenants under our 9% senior unsecured notes;
- changes in our creditworthiness; and
- the outcome of certain shareholder class action lawsuits.

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 or cash flows 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.

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 and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under PPAs, which seek to minimize exposure to changes in commodity prices. As of June 30, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 3,018 MW in which our aggregate ownership interest is approximately 2,098 MW. These totals exclude our 17.1% interest in Gregory which was sold August 7, 2013, and our 40% interest in the Delta-Person for which we entered into an agreement to sell in December 2012. Our current portfolio of continuing operations consists of interests in twenty-nine operational power generation projects across eleven states in the United States and two provinces in Canada. Piedmont, our 53 MW biomass project in Georgia, achieved commercial operations in April 2013. We also own a wind and solar development company, Ridgeline, located in Seattle, Washington, which enhances our ability to develop, construct, and operate wind and solar energy projects across the United States and Canada. We also own a majority interest in Rollcast, a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly owned subsidiaries.

We sell 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 2013 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.

Our power generation projects generally 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 more than half 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"), Power Plant Management Services ("PPMS") and Delta Power Services ("DPS"). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

RECENT DEVELOPMENTS

Amended Credit Facility

On August 2, 2013, we entered into the amended credit facility with our lenders to amend our senior credit facility primarily to obtain more favorable financial ratios. The amended credit facility includes changes to our borrowing capacity, financial ratios and certain other customary representations, warranties, terms and conditions and covenants. For a description of these changes, see " Liquidity and Capital Resources" and Note 5 to the consolidated financial statements included in this Quarterly Report on Form 10-Q.

Goodwill Impairment Testing

Subsequent to the three months ended June 30, 2013, based on a prolonged decline in our market capitalization and initiatives started at reducing our development and administrative expenses, we determined that it was appropriate to initiate a test of goodwill 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 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, 2013.

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During the three months ended June 30, 2013, we recorded a $3.5 million impairment of goodwill at Rollcast which is a component of our Un-allocated corporate segment. We determined, based on the results of the two-step process, that the carrying amount of goodwill exceeded the implied fair value of goodwill. We also wrote-off $1.4 million of capitalized development costs at Rollcast related to the Greenway development project. The determination to impair goodwill and write-off the capitalized development costs was based on the reduced expectation of the Greenway project being further developed.

Administration and Development Reductions

In July 2013 we implemented changes in several key areas that are expected to result in an approximate $8.0 million reduction to administration and development expenses relative to our previous budget. The expense reductions will occur in three broad areas, which are, in order of significance: (1) reduction in the development budget, both for personnel and third-party expenses, consistent with de-emphasizing early-stage development projects; (2) consolidation of accounting and finance functions in two offices, down from three; and (3) additional synergies from full integration of areas such as health care, plant insurance, IT, travel and other functions.

Most of the one-time costs that will be incurred to implement these changes will be recorded in the third and fourth quarters of 2013. The savings are expected to be realized beginning in 2014. However, the Company may experience increases in unrelated costs such as those associated with its debt reduction objectives and plant optimization initiatives. The net impact on cash flows is expected to be positive in 2014.

Piedmont Commercial Operations and Receipt of Grant Proceeds

In May 2013, Piedmont submitted an application under the federal 1603 grant program. In July, the grant was approved and $49.5 million was received from the U.S. Treasury. With the proceeds received and a $1.5 million contribution from Atlantic Power to cover the shortfall created by the U.S. federal budget sequestration, the project's outstanding $51 million bridge loan was fully repaid in July 2013. Piedmont's construction loan in the amount of $82 million ($75.1 million at June 30, 2013) is expected to convert to a term loan in the third quarter of 2013. We contributed an additional $2.7 million equity investment during the three months ended June 30, 2013 to fund the project's working capital.

Piedmont achieved commercial operation under its PPA with Georgia Power Company at a declared capacity of 53.5 MW on April 19, 2013. Piedmont and its engineering, procurement and construction ("EPC") contractor, Zachry Industrial, Inc. ("Zachry"), are disputing certain issues under the EPC agreement regarding the condition and performance of the project, during which time Piedmont is withholding the amount still retained under the agreement.

Canadian Hills Tax Equity

On May 2, 2013, we syndicated our $44.0 million tax equity investment in Canadian Hills to an institutional investor and received cash proceeds of $42.1 million. The cash proceeds received were based on our initial tax equity investment of $44.1 million less distributions received from Canadian Hills resulting in an immaterial loss on the sale. During this short-term ownership as a tax equity investor in the project, we generated an immaterial amount of production tax credits and approximately $5.5 million of net operating losses, which we will be able to use to offset against future taxable income. The syndication of our interest completes the sale of 100% of Canadian Hills' $269 million of tax equity interests. The cash proceeds will be held for general corporate purposes. We continue to own 99% of the project and consolidate it in our consolidated financial statements. Income, (losses), and distributions attributable to the tax investors are recorded as a component of noncontrolling interests.

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Sale of Gregory

On April 2, 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 from our ownership interest of approximately $34.6 million in the aggregate, after repayment of project-level debt and transaction expenses. Approximately $5 million of these proceeds will be held in escrow for up to one year after the closing date. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Gregory closed on August 7, 2013 resulting in a gain of approximately $31 million that will be recorded in the three months ended September 30, 2013.

Sale of Path 15

On March 11, 2013 we entered into a purchase and sale agreement with Duke-American Transmission Company, a joint venture between Duke Energy Corporation and American Transmission Co., to sell our interests in 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 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56 million. The cash proceeds will be 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 an asset held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013 and 2012.

Sale of Florida Projects

On January 30, 2013, we entered into a purchase and sale agreement for the sale of the Florida Projects, for approximately $140 million, with working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117 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 million received at closing and cash distributions from the projects of approximately $25 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 on the closing date. The Florida Projects were accounted for as assets held for sale in the consolidated balance sheets at December 31, 2012 and are a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2013 and 2012.

OUR POWER PROJECTS

The table on the following page outlines our portfolio of power generating assets in operation as of August 5, 2013, 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"). Customers that have assigned ratings at the top end of the range have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the bottom end of the range have the weakest 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 is not a recommendation to buy, sell or hold securities, it 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)
Northeast Segment								
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	December 2028	BBB
Chambers	New Jersey	Coal	262	40.00%	89	Atlantic City Elec.	December 2024	BBB+
					16	DuPont	December 2024	A
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Merck, & Co., Inc.	September 2018(1)	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	December 2027	A-
Selkirk	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	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	December 2014	AA-

Southeast Segment								
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	December 2023	BBB+
					19	Reedy Creek Improvement District(2)	December 2013	A
Piedmont	Georgia	Biomass	53	98.0%	52	Georgia Power	December 2032	A
Northwest 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
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	December 2030	BBB
Rockland	Idaho	Wind	80	50.00%	40	Idaho Power Co.	December 2036	BBB
Goshen North	Idaho	Wind	125	12.50%	16	Southern California Edison	November 2030	BBB+
Meadow Creek	Idaho	Wind	120	100.00%	120	PacifiCorp	December 2032	A-
Frederickson	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	Washington	Hydro	13	49.80%	6	Puget Sound Energy	December 2037	BBB

Southwest Segment								
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	40	100.00%	40	San Diego Gas & Electric	December 2019	A
Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	May 2020	BBB+
Greeley	Colorado	Natural Gas	72	100%	72	Public Service Company of Colorado	August 2013(3)	A-
Manchief	Colorado	Natural Gas	300	100%	300	Public Service Company of Colorado	October 2022	A-
Morris	Illinois	Natural Gas	177	100%	77	Merchant	N/A	N/R
					100	Equistar Chemicals, LP	November 2023	BBB
Canadian Hills	Oklahoma	Wind	298	99.0%	199	Southwestern Electric Power Company	December 2037	BBB
					48	Oklahoma Municipal Power Authority	December 2037	A
					48	Grand River Dam Authority	December 2032	A

(1) The Kenilworth Energy Service Agreement ("ESA"), under which Kenilworth sells electricity and steam to Merck expired on July 31, 2012 and was extended on a month-to month basis by agreement with the purchaser. In July 2013, we entered into a new ESA with Merck that becomes effective November 1, 2013 and expires on September 30, 2018. Kenilworth will operate under the month-to-month extension of the prior ESA until the new ESA is effective.

(2) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to Progress Energy Florida under the terms of the current agreement.

(3) The Greeley project will be shut down at the expiration of its PPA in August 2013.

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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, 2013 and 2012 which are analyzed in greater detail below:

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Project income (loss)	$ 15.6	$ (7.5)	$ 46.7	$ (44.5)
Income (loss) from continuing operations	1.9	(21.4)	8.8	(72.2)
Income (loss) from discontinued operations, net of tax	(0.7)	19.3	0.2	30.9
Net income (loss) attributable to Atlantic Power Corporation	(3.0)	(5.1)	3.5	(47.4)
Basic and diluted earnings (loss) per share from continuing operations	$ (0.02)	$ (0.21)	$ 0.03	$ (0.69)
Project Adjusted EBITDA[1]	56.2	45.4	136.8	111.9
Cash Available for Distribution[1]	(6.7)	13.0	75.0	72.8

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

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Three months ended June 30, 2013 compared to the three months ended June 30, 2012

The following table provides our consolidated results of operations:

	Three months ended June 30,			
	2013	**2012**	**$ change**	**% change**
Project revenue:				
Energy sales	$ 68.1	$ 49.4	18.7	37.9%
Energy capacity revenue	54.4	37.5	16.9	45.1%
Other	16.5	14.5	2.0	13.8%
	139.0	101.4	37.6	37.1%
Project expenses:				
Fuel	52.0	37.3	14.7	39.4%
Operations and maintenance	46.9	37.9	9.0	23.7%
Development	1.8		1.8	NM
Depreciation and amortization	42.2	30.3	11.9	39.3%
	142.9	105.5	37.4	35.5%
Project other income (expense):				
Change in fair value of derivative instruments	24.3	(4.8)	29.1	NM
Equity in earnings of unconsolidated affiliates	8.7	5.5	3.2	58.2%
Interest expense, net	(8.7)	(4.1)	(4.6)	112.2%
Other, net	(4.8)		(4.8)	NM
	19.5	(3.4)	22.9	NM
Project income (loss)	15.6	(7.5)	23.1	NM
Administrative and other expenses (income):				
Administration	11.8	8.0	3.8	47.5%
Interest, net	25.3	21.4	3.9	18.2%
Foreign exchange (gain) loss	(14.5)	(4.2)	(10.3)	NM
Other income, net	(9.5)	(6.0)	(3.5)	58.3%
	13.1	19.2	(6.1)	-31.8%
Income (loss) from continuing operations before income taxes	2.5	(26.7)	29.2	109.4%
Income tax expense (benefit)	0.6	(5.3)	5.9	111.3%
Income (loss) from continuing operations	1.9	(21.4)	23.3	108.9%
Income (loss) from discontinued operations, net of tax	(0.7)	19.3	(20.0)	-103.6%
Net income (loss)	1.2	(2.1)	3.3	NM
Net income (loss) attributable to noncontrolling interests	1.1	(0.2)	1.3	NM
Net income attributable to preferred shares dividends of a subsidiary company	3.1	3.2	(0.1)	-3.1%
Net loss attributable to Atlantic Power Corporation	$ (3.0)	$ (5.1)	2.1	41.2%

Project Income (loss) by Segment

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure, costs of being a public registrant in the United States and Canada, costs to develop future projects and intercompany eliminations. Unallocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel and Ridgeline, which develops and operates wind and solar renewable projects.

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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. A significant non-cash item that impacts project income (loss) and is subject to potentially significant fluctuations is the change in fair value of certain derivative financial instruments. These instruments are required by GAAP to be revalued at each balance sheet date (see Item 3. "Quantitative and Qualitative Disclosures About Market Risk" for additional information).

	Three months ended June 30, 2013					
	Northeast	Southeast[1]	Northwest	Southwest[2]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 29.5	$ 2.1	$ 16.7	$ 19.4	$ 0.4	$ 68.1
Energy capacity revenue	21.1	4.0		29.6	(0.3)	54.4
Other	2.2	0.1	4.6	9.7	(0.1)	16.5
	52.8	6.2	21.3	58.7		139.0
Project expenses:						
Fuel	23.7	2.9	1.2	24.2		52.0
Operations and maintenance	11.9	3.2	13.6	16.3	1.9	46.9
Development					1.8	1.8
Depreciation and amortization	15.1	1.6	10.9	14.2	0.4	42.2
	50.7	7.7	25.7	54.7	4.1	142.9
Project other income (expense):						
Change in fair value of derivative instruments	7.9	2.3	14.1			24.3
Equity in earnings of unconsolidated affiliates	5.7	0.8	1.8	0.1	0.3	8.7
Interest expense, net	(4.0)	(1.2)	(3.4)	(0.2)	0.1	(8.7)
Other, net					(4.8)	(4.8)
	9.6	1.9	12.5	(0.1)	(4.4)	19.5
Project income (loss)	$ 11.7	$ 0.4	$ 8.1	$ 3.9	$ (8.5)	$ 15.6

	Three months ended June 30, 2012					
	Northeast	Southeast[1]	Northwest	Southwest[2]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 26.6	$	$ 11.6	$ 11.0	$ 0.2	$ 49.4
Energy capacity revenue	17.2			20.4	(0.1)	37.5
Other	2.1		5.1	6.8	0.5	14.5
	45.9		16.7	38.2	0.6	101.4
Project expenses:						
Fuel	22.9		1.2	13.0	0.2	37.3
Operations and maintenance	12.2		8.4	12.7	4.6	37.9
Development						
Depreciation and amortization	15.2		6.6	8.5		30.3
	50.3		16.2	34.2	4.8	105.5
Project other income (expense):						
Change in fair value of derivative instruments	(1.3)	(3.2)			(0.3)	(4.8)
Equity in earnings of unconsolidated affiliates	8.5	0.7	(0.2)	(3.5)		5.5
Interest expense, net	(4.0)				(0.1)	(4.1)

	3.2	(2.5)	(0.2)	(3.5)	(0.4)	(3.4)
Project income (loss)	$ (1.2)	$ (2.5)	$ 0.3	$ 0.5	$ (4.6)	$ (7.5)

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

(2) Excludes Path 15 which is designated as discontinued operations.

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Northeast

Project income for the three months ended June 30, 2013 increased $12.9 million from the comparable 2012 period primarily due to:

- increased project income from Nipigon of $8.6 million due primarily to a positive $8.9 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Curtis Palmer of $4.7 million due primarily to increased generation resulting from higher water levels than the comparable period; and

- increased project income from Calstock of $2.9 million due primarily to steam turbine maintenance in the second quarter of 2012 that contributed to increased generation, lower maintenance costs, and lower fuel costs in the comparable period.

These increases were partially offset by:

- decreased project income from Tunis of $2.1 million due primarily to higher maintenance and fuel costs than in the comparable period.

Southeast

Project income for the three months ended June 30, 2013 increased $2.9 million from the comparable 2012 period primarily due to the Piedmont project becoming commercially operational in April 2013 which contributed project income of $4.0 million. Piedmont's project income was primarily due to a positive $6.6 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives, partially offset by fuel, maintenance and interest expenses.

Project income for the Southeast segment excludes the Florida Projects which are accounted for as a component of discontinued operations and were sold on April 12, 2013. Project income for the Florida Projects was immaterial for the three months ended June 30, 2013 and was $19.7 million for the three months ended June 30, 2012.

Northwest

Project income for the three months ended June 30, 2013 increased $7.8 million from the comparable 2012 period primarily due to:

- increased project income from Rockland of $6.8 million attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition in December 2012; and

- project income of $5.4 million from Meadow Creek, which was a component of the Ridgeline acquisition and achieved commercial operations in December 2012. Meadow Creek's project income was primarily attributable to a positive $6.9 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives.

These increases were partially offset by:

- decreased project income from Williams Lake of $3.1 million due primarily to higher operations and maintenance costs from a scheduled outage; and

- decreased project income from Mamquam of $2.2 million due primarily to higher maintenance costs from a scheduled outage and decreased revenues from lower generation.

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Southwest

Project income for the three months ended June 30, 2013 increased $3.4 million from the comparable 2012 period primarily due to:

- project income from Canadian Hills of $1.8 million due primarily to the project becoming commercially operational during the fourth quarter of 2012; and

- $3.6 million of project loss in the comparable 2012 from the Badger and PERC projects which were sold in 2012.

These increases were partially offset by:

- decreased project income from Morris of $2.0 million due primarily to higher maintenance costs, higher fuel expenses, and lower revenues.

Project income for the Southwest segment excludes the Path 15 project which was sold on April 30, 2013 and which is accounted for as an asset held for sale and as a component of discontinued operations. Project income (loss) for Path 15 was $1.1 million and $(0.4) million for the three months ended June 30, 2013 and 2012, respectively and did not change materially.

Un-allocated Corporate

Total project loss increased $3.9 million for the three months ended June 30, 2013 from the comparable 2012 period primarily due to a $3.5 million non-cash impairment of goodwill charge and a $1.4 million non-cash impairment of capitalized development expenses recorded at Rollcast.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive offices, capital structure, costs of being a public registrant in the United States and Canada, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which 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 increased $3.8 million or 47.5% from the comparable 2012 period primarily due to transactional fees related to divestitures during the three months ended June 30, 2013.

Interest, net

Interest expense increased $3.9 million or 18.2% from the comparable 2012 period primarily due to the issuance of the $130 million principal amount of convertible debentures in July of 2012 and issuance of the Cdn$100 million principal amount of convertible debentures in December of 2012.

Foreign exchange gain

Foreign exchange gain increased $10.3 million primarily due to a $7.7 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars and a $7.7 million increase in realized gains on the settlement of foreign currency forward contracts, offset by a $5.1 million increase in unrealized loss of foreign currency forward contracts. The U.S. dollar to

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Canadian dollar exchange rate was 1.05 at June 30, 2013 and increased by 3.5% in three months ended June 30, 2013 compared to a 2.1% increase in the comparable 2012 period. In April 2013, we terminated various foreign currency forward contracts with expiration dates through 2015 resulting in a $9.4 million realized gain recorded in the three months ended June 30, 2013.

Other income, net

Other income increased $3.5 million or 58.3% from the comparable 2012 period primarily due to a $10.3 million gain and management agreement termination fee resulting from the sale of Path 15. In the comparable 2012 period, we recorded a $6.0 million management agreement termination fee related to the sale of our equity interest in Primary Energy Holdings, LLC ("PERH").

Income tax expense (benefit)

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%.

Income tax benefit for the three months ended June 30, 2012 was $5.3 million. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $6.7 million for the three months ended June 30, 2012 is primarily due to permanent differences related to one of our equity method projects.

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Six months ended June 30, 2013 compared to the six months ended June 30, 2012

The following table provides our consolidated results of operations:

	Six months ended June 30,			
	2013	2012	$ change	% change
Project revenue:				
Energy sales	$ 137.1	$ 109.4	27.7	25.3%
Energy capacity revenue	99.2	74.5	24.7	33.2%
Other	42.9	36.2	6.7	18.5%
	279.2	220.1	59.1	26.9%
Project expenses:				
Fuel	101.6	83.5	18.1	21.7%
Operations and maintenance	75.2	62.6	12.6	20.1%
Development	3.5		3.5	NM
Depreciation and amortization	83.5	56.8	26.7	47.0%
	263.8	202.9	60.9	30.0%
Project other income (expense):				
Change in fair value of derivative instruments	36.9	(62.0)	98.9	159.5%
Equity in earnings of unconsolidated affiliates	15.9	8.4	7.5	89.3%
Interest expense, net	(16.7)	(8.1)	(8.6)	106.2%
Other, net	(4.8)		(4.8)	NM
	31.3	(61.7)	93.0	150.7%
Project income (loss)	46.7	(44.5)	91.2	204.9%
Administrative and other expenses (income):				
Administration	20.1	15.7	4.4	28.0%
Interest, net	51.2	43.4	7.8	18.0%
Foreign exchange (gain) loss	(22.0)	(3.2)	(18.8)	NM
Other income, net	(9.5)	(6.0)	(3.5)	58.3%
	39.8	49.9	(10.1)	-20.2%
Income (loss) from continuing operations before income taxes	6.9	(94.4)	101.3	107.3%
Income tax benefit	(1.9)	(22.2)	20.3	91.4%
Income (loss) from continuing operations	8.8	(72.2)	81.0	112.2%
Income from discontinued operations, net of tax	0.2	30.9	(30.7)	-99.4%
Net income (loss)	9.0	(41.3)	50.3	121.8%
Net loss attributable to noncontrolling interests	(0.8)	(0.3)	(0.5)	166.7%
Net income attributable to preferred shares dividends of a subsidiary company	6.3	6.4	(0.1)	-1.6%
Net income (loss) attributable to Atlantic Power Corporation	$ 3.5	$ (47.4)	50.9	107.4%

Project Income (loss) by Segment

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure, costs of being a public registrant in the United States and Canada, costs to develop future projects and intercompany eliminations. Unallocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel and Ridgeline, which develops and operates wind and solar renewable projects.

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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. A significant non-cash item that impacts project income (loss) and is subject to potentially significant fluctuations is the change in fair value of certain derivative financial instruments. These instruments are required by GAAP to be revalued at each balance sheet date (see Item 3. "Quantitative and Qualitative Disclosures About Market Risk" for additional information).

	Six months ended June 30, 2013					
	Northeast	Southeast[(1)]	Northwest	Southwest[(2)]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 65.5	$ 2.1	$ 34.1	$ 35.1	$ 0.3	$ 137.1
Energy capacity revenue	43.8	4.0		51.5	(0.1)	99.2
Other	11.3	0.1	11.9	20.1	(0.5)	42.9
	120.6	6.2	46.0	106.7	(0.3)	279.2
Project expenses:						
Fuel	49.0	2.9	4.5	45.2		101.6
Operations and maintenance	20.0	3.2	19.4	28.5	4.1	75.2
Development					3.5	3.5
Depreciation and amortization	30.3	1.6	22.6	28.6	0.4	83.5
	99.3	7.7	46.5	102.3	8.0	263.8
Project other income (expense):						
Change in fair value of derivative instruments	16.3	3.6	16.9		0.1	36.9
Equity in earnings of unconsolidated affiliates	11.2	1.4	2.5	0.7	0.1	15.9
Interest expense, net	(8.0)	(1.2)	(7.0)	(0.4)	(0.1)	(16.7)
Other, net					(4.8)	(4.8)
	19.5	3.8	12.4	0.3	(4.7)	31.3
Project income (loss)	$ 40.8	$ 2.3	$ 11.9	$ 4.7	$ (13.0)	$ 46.7

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	Six months ended June 30, 2012					
	Northeast	Southeast(1)	Northwest	Southwest(2)	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 64.8	$	$ 20.4	$ 24.0	$ 0.2	$ 109.4
Energy capacity revenue	39.5			35.0		74.5
Other	8.5		11.6	14.7	1.4	36.2
	112.8		32.0	73.7	1.6	220.1
Project expenses:						
Fuel	49.1		4.9	29.2	0.3	83.5
Operations and maintenance	21.0		12.2	20.5	8.9	62.6
Development						
Depreciation and amortization	27.4		13.1	16.4	(0.1)	56.8
	97.5		30.2	66.1	9.1	202.9
Project other income (expense):						
Change in fair value of derivative instruments	(59.2)	(1.8)			(1.0)	(62.0)
Equity in earnings of unconsolidated affiliates	12.5	0.5	0.4	(5.7)	0.7	8.4
Interest expense, net	(7.9)				(0.2)	(8.1)
	(54.6)	(1.3)	0.4	(5.7)	(0.5)	(61.7)
Project income (loss)	$ (39.3)	$ (1.3)	$ 2.2	$ 1.9	$ (8.0)	$ (44.5)

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

(2) Excludes Path 15 which is designated as discontinued operations.

Northeast

Project income for the six months ended June 30, 2013 increased $80.1 million from the comparable 2012 period primarily due to:

- increased project income from North Bay of $31.1 million due primarily to a positive $32.1 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Kapuskasing of $30.8 million due primarily to a positive $32.1 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Nipigon of $11.8 million due primarily to a positive $10.7 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Calstock of $4.4 million due primarily to steam turbine maintenance that occurred in the comparable 2012 period; and increased project income from Curtis Palmer of $2.7 million due primarily to increased generation resulting from higher water levels than the comparable period.

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These increases were partially offset by:

- decreased project income from Tunis of $2.9 million due primarily to lower generation and energy prices than in the comparable period.

Southeast

Project income for the six months ended June 30, 2013 increased $3.6 million from the comparable 2012 period primarily due to the Piedmont project becoming commercially operational in April 2013. Piedmont's $3.5 million of project income was primarily due to a positive $6.1 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives. The gain was offset by increased maintenance and interest expenses.

Project income for the Southeast segment excludes the Florida Projects which are accounted for as a component of discontinued operations and were sold on April 12, 2013. Project income for the Florida Projects was immaterial for the six months ended June 30, 2013 and was $30.2 million for the six months ended June 30, 2012.

Northwest

Project income for the six months ended June 30, 2013 increased $9.7 million from the comparable 2012 period primarily due to:

- increased project income from Rockland of $7.8 million attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition during the fourth quarter of 2012; and

- project income from Meadow Creek of $4.3 million which achieved commercial operations in December 2012. Meadow Creek's project income was primarily due to a positive $8.6 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives. This gain was offset by $4.2 million of interest expense.

These increases were partially offset by:

- decreased project income from Mamquam of $2.7 million due primarily to increased maintenance costs from a scheduled outage and lower revenues than the comparable period.

Southwest

Project income for the six months ended June 30, 2013 increased $2.8 million from the comparable 2012 period primarily due to:

- project income from Canadian Hills of $2.7 million which achieved commercial operations in December 2012.

These increases were partially offset by:

- decreased project income from Morris of $4.8 million due primarily to higher maintenance costs from a scheduled outage, higher fuel expenses, and lower revenues in the comparable period.

Project income for the Southwest segment excludes the Path 15 project, which was sold on April 30, 2013 and which is accounted for as a component of discontinued operations. Project income for Path 15 was $2.1 million and $1.3 million for the six months ended June 30, 2013 and 2012, respectively and did not change materially.

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Un-allocated Corporate

Total project loss increased $5.0 million for the six months ended June 30, 2013 from the comparable 2012 period primarily due to a $3.5 million non-cash impairment of goodwill charge and a $1.4 million non-cash impairment of capitalized development expenses recorded at Rollcast.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive offices, capital structure, costs of being a public registrant in the United States and Canada, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which 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 increased $4.4 million or 28.0% from the comparable 2012 period primarily due to transactional fees during the six months ended June 30, 2013 related to divestitures.

Interest, net

Interest expense increased $7.8 million or 18.0% from the comparable 2012 period primarily due to the issuance of the $130 million principal amount of convertible debentures in July of 2012 and issuance of the Cdn$100 million principal amount of convertible debentures in December of 2012.

Foreign exchange (gain)

Foreign exchange gain increased $18.8 million primarily due to a $26.4 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars offset by a $5.9 million increase in unrealized loss on foreign exchange forward contracts and a $1.7 million decrease in realized gains on the settlement of foreign currency forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.05 at June 30, 2013 and increased by 5.7% in the six months ended June 30, 2013 compared to a 0.1% increase in the comparable 2012 period.

Other income, net

Other income increased $3.5 million or 58.3% from the comparable 2012 period primarily due to a $10.3 million gain and management agreement termination fee resulting from the sale of Path 15. In the comparable 2012 period, we recorded a $6.0 million management agreement termination fee related to the sale of our equity interest in PERH.

Income tax expense (benefit)

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.

Income tax benefit for the six months ended June 30, 2012 was $22.2 million. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $23.6 million for the six months ended June 30, 2012 is primarily due to permanent differences related to one of our equity method projects and is partially offset by the increase in our valuation allowance.

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Generation and Availability

	Three months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Aggregate power generation (thousands of Net MWh)			
Northeast	640.0	536.7	19.2%
Southeast[(1)]	181.5	103.6	75.2%
Northwest	376.3	312.4	20.5%
Southwest[(2)]	878.4	441.3	99.0%
Total	2,076.2	1,394.0	48.9%
Weighted average availability			
Northeast	96.5%	91.8%	5.1%
Southeast[(1)]	92.5%	100.0%	-7.5%
Northwest	88.4%	95.2%	-7.1%
Southwest[(2)]	90.3%	90.2%	0.1%
Total	93.1%	94.8%	-1.8%

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

(2) Excludes Delta-Person for which we have entered into an agreement to sell and Gregory which was sold on August 7, 2013.

Three months ended June 30, 2013 compared with three months ended June 30, 2012

Aggregate power generation for the three months ended June 30, 2013 increased 48.9% from the comparable 2012 period primarily due to:

- increased generation in the Northeast segment due to higher water flow at Curtis Palmer and increased dispatch at Chambers and Selkirk;
- increased generation in the Southeast segment due to Piedmont, which achieved commercial operations in April 2013;
- increased generation in the Northwest segment primarily due to Meadow Creek, which achieved commercial operations in late December 2012, as well as generation from Goshen North. Both projects were acquired in December 2012; and
- increased generation in the Southwest segment due to Canadian Hills, which achieved commercial operations in late December 2012 and increased dispatch at Manchief.

Weighted average availability decreased from 94.8% for the three months ended June 30, 2012 to 93.1% for the three months ended June 30, 2013 period primarily due to:

- decreased availability in the Southeast segment resulting from Piedmont, which achieved commercial operations in April 2013 and had low availability consistent with the initial start-up period of a new plant; and
- decreased availability in the Northwest segment resulting from decreased availability at Mamquam, Moresby Lake and Williams Lake which underwent scheduled maintenance during the three months ended June 30, 2013. This was partially offset by increased availability at Meadow Creek and Goshen which were acquired in December 2012.

This was partially offset by

- increased availability in the Northeast segment due to Calstock and Tunis which had scheduled maintenance outages in the three months ended June 30, 2012.

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Generation (in thousands of Net MWh) and availability statistics for the Southeast segment exclude the Florida Projects which are accounted for as a component of discontinued operations. Total generation for Auburndale was 265.9 MWh and availability was 98.2% for the three months ended June 30, 2012. Total generation for Lake was 122.6 MWh and availability was 99.7% for the three months ended June 30, 2012. Total generation for Pasco was 95.3 MWh and availability was 95.0% for the three months ended June 30, 2012. Generation statistics for the Florida Projects were not material for the period of our ownership prior to the sale during the three months ended June 30, 2013.

	Six months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Aggregate power generation (thousands of Net MWh)			
Northeast	1,337.8	1,201.9	11.3%
Southeast[(1)]	286.4	208.3	37.5%
Northwest	728.6	560.4	30.0%
Southwest[(2)]	1,635.7	915.9	78.6%
Total	3,988.5	2,886.5	38.2%
Weighted average availability			
Northeast	96.3%	95.2%	1.2%
Southeast[(1)]	95.6%	100.0%	-4.4%
Northwest	89.9%	94.2%	-4.6%
Southwest[(2)]	92.7%	93.7%	-1.1%
Total	94.1%	92.2%	2.1%

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

(2) Excludes Delta-Person for which we have entered into an agreement to sell and Gregory which was sold on August 7, 2013.

Six months ended June 30, 2013 compared with six months ended June 30, 2012

Aggregate power generation for the six months ended June 30, 2013 increased 38.2% from the comparable 2012 period primarily due to:

- increased generation in the Northeast segment due to increased dispatch at Chambers and Selkirk;
- increased generation in the Southeast segment due to Piedmont, which achieved commercial operations in April 2013;
- increased generation in the Northwest segment primarily due to Meadow Creek, which achieved commercial operations in late December 2012, as well as generation from Goshen North and increased ownership of Rockland, all of which resulted from our December 2012 acquisition of Ridgeline; and
- increased generation in the Southwest segment due to Canadian Hills, which achieved commercial operations in late December 2012 and increased dispatch at Manchief.

Weighted average availability increased from 92.2% for the six months ended June 30, 2012 to 94.1% for the six months ended June 30, 2013 period primarily due to:

- increased availability in the Northeast segment due to Calstock, which had a scheduled maintenance outage in April 2012, and increased availability at Selkirk, which had higher dispatch than the comparable 2012 period.

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This was partially offset by

- decreased availability in the Southeast segment resulting from Piedmont, which achieved commercial operations in April 2013 and had low availability consistent with the initial start-up period of a new plant;

- decreased availability in the Northwest segment resulting from decreased availability at Mamquam, Moresby Lake and Williams Lake which underwent scheduled maintenance during the three months ended June 30, 2013. This was partially offset by increased availability at Meadow Creek and Goshen which were acquired in December 2012; and

- decreased availability in the Southwest segment resulting from scheduled maintenance at Morris during the first quarter of 2013 and a forced maintenance outage in June 2013.

Generation (in thousands of Net MWh) and availability statistics for the Southeast segment exclude the Florida Projects which are accounted for as a component of discontinued operations. Total generation for Auburndale was 456.1 MWh and availability was 98.7% for the six months ended June 30, 2012. Total generation for Lake was 240.6 MWh and availability was 98.9% for the six months ended June 30, 2012. Total generation for Pasco was 141.6 MWh and availability was 96.3% for the six months ended June 30, 2012. Generation statistics for the Florida Projects were not material for the period of our ownership prior to the sale during the three months ended June 30, 2013. Total generation for Auburndale was approximately 270 MWh and availability was approximately 98.8% for the six months ended June 30, 2013. Total generation for Lake was approximately 240 MWh and availability was approximately 97.3% for the six months ended June 30, 2013. Total generation for Pasco was approximately 40 MWh and availability was approximately 91.6% for the six months ended June 30, 2013.

Supplementary Non-GAAP Financial Information

A key measure we use to evaluate the results of our business is Cash Available for Distribution. Cash Available for Distribution 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 Cash Available for Distribution is a relevant supplemental measure of our ability to pay dividends to our shareholders. A reconciliation of cash flows from operating activities, the most directly comparable GAAP measure, to Cash Available for Distribution is set out below under "Cash Available for Distribution." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received 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 company 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 income (loss) to Project Adjusted EBITDA is set out below by segment under "Project Adjusted EBITDA" and a reconciliation of project income (loss) by segment to Project Adjusted EBITDA by segment is set out in Note 13 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.

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Project Adjusted EBITDA

(unaudited)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Project Adjusted EBITDA by Segment				
Northeast	$ 26.0	$ 22.4	$ 71.9	$ 64.8
Southeast[1]	2.4	2.1	4.5	4.2
Northwest	12.3	12.4	33.6	25.9
Southwest[2]	19.0	12.6	35.0	24.7
Un-allocated Corporate	(3.5)	(4.1)	(8.2)	(7.7)
Total	56.2	45.4	136.8	111.9
Reconciliation to project income (loss)				
Depreciation and amortization	50.6	41.3	103.0	81.1
Interest, net	9.5	6.4	19.0	12.4
Change in the fair value of derivative instruments	(26.8)	2.1	(38.3)	59.6
Other (income) expense	7.3	3.1	6.4	3.3
Project income (loss)	15.6	(7.5)	46.7	(44.5)

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

(2) Excludes Path 15 which is designated as discontinued operations.

Northeast

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

	Three months ended June 30, 2013	2012	% change 2013 vs. 2012
Northeast			
Project Adjusted EBITDA	$ 26.0	$ 22.4	16%

Three months ended June 30, 2013 compared with three months ended June 30, 2012

Project Adjusted EBITDA for the three months ended June 30, 2013 increased $3.6 million or 16% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $4.6 million at Curtis Palmer primarily attributable to increased generation resulting from higher water levels than the comparable period; and

- $2.9 million at Calstock which had steam turbine maintenance in comparable 2012 period.

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

- $3.7 million at Chambers primarily attributable to the collection of the DuPont partial settlement associated with the dispute of the electricity calculation under its PPA in the second quarter of 2012.

Six months ended June 30,

	2013	2012	% change 2013 vs. 2012
Northeast			
Project Adjusted EBITDA	$ 71.9	$ 64.8	11%

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Six months ended June 30, 2013 compared with six months ended June 30, 2012

Project Adjusted EBITDA for the six months ended June 30, 2013 increased $7.1 million or 11% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $4.4 million at Calstock primarily attributable to steam turbine maintenance that occurred in the second quarter of 2012;

- $2.8 million at Curtis Palmer primarily attributable to increased generation resulting from higher water flows than the comparable period in 2012; and

- $2.3 million at Kenilworth primarily attributable to increased capacity revenues under the month to month renewal of the project's energy service arrangement.

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

- $3.8 million at Chambers primarily attributable to the collection of the DuPont partial settlement associated with the dispute of the electricity calculation under its PPA in the second quarter of 2012; and

- $2.3 million at Tunis primarily attributable to lower generation and energy prices.

Southeast

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

	Three months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Southeast			
Project Adjusted EBITDA	$ 2.4	$ 2.1	NM

Three months ended June 30, 2013 compared with three months ended June 30, 2012

Project Adjusted EBITDA in the Southeast segment did not change materially. Piedmont, which achieved commercial operations in April 2013, had $0.2 million of Project Adjusted EBITDA for the three months ended June 30, 2013.

Project Adjusted EBITDA for the Southeast segment excludes the Florida Projects which are accounted for as a component of discontinued operations. Project Adjusted EBITDA for Auburndale was $1.9 million and $12.9 million for the three months ended June 30, 2013 and 2012, respectively, Project Adjusted EBITDA for Lake was $0.6 million and $9.2 million for the three months ended June 30, 2013 and 2012, respectively and Project Adjusted EBITDA for Pasco was $0.2 million and $0.9 million for the three months ended June 30, 2013 and 2012, respectively. The decrease is attributable to the projects being sold in April 2013.

	Six months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Southeast			
Project Adjusted EBITDA	$ 4.5	$ 4.2	NM

Six months ended June 30, 2013 compared with six months ended June 30, 2012

Project Adjusted EBITDA in the Southeast segment did not change materially. Piedmont, which achieved commercial operations in April 2013, had $0.2 million of Project Adjusted EBITDA for the six months ended June 30, 2013.

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Project Adjusted EBITDA for the Southeast segment excludes the Florida Projects which are accounted for as a component of discontinued operations. Project Adjusted EBITDA for Auburndale was $12.4 million and $23.4 million for the six months ended June 30, 2013 and 2012, respectively, Project Adjusted EBITDA for Lake was $13.7 million and $17.3 million for the six months ended June 30, 2013 and 2012, respectively and Project Adjusted EBITDA for Pasco was $1.2 million and $1.8 million for the six months ended June 30, 2013 and 2012, respectively. The decrease is attributable to the projects being sold in April 2013.

Northwest

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

	Three months ended June 30,		
	2013	**2012**	**% change 2013 vs. 2012**
Northwest			
Project Adjusted EBITDA	$ 12.3	$ 12.4	NM

Three months ended June 30, 2013 compared with three months ended June 30, 2012

Project Adjusted EBITDA for the three months ended June 30, 2013 decreased by $0.1 million from the comparable 2012 period primarily due to decreases in Project Adjusted EBITDA of:

$2.2 million at Mamquam resulting from higher maintenance costs due to a scheduled outage and decreased revenues caused by lower water levels; and

$3.1 million at Williams Lake resulting from lower generation and higher maintenance costs from a scheduled outage and decreased revenues due to a lower firm energy price beginning in April 2013 under the PPA.

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

$3.4 million at Meadow Creek which achieved commercial operations in December 2012; and

$1.2 million at Rockland attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition in December 2012.

	Six months ended June 30,		
	2013	**2012**	**% change 2013 vs. 2012**
Northwest			
Project Adjusted EBITDA	$ 33.6	$ 25.9	30%

Six months ended June 30, 2013 compared with six months ended June 30, 2012

Project Adjusted EBITDA for the six months ended June 30, 2013 increased by $7.7 million or 30% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

$6.5 million at Meadow Creek which achieved commercial operations and was part of the Ridgeline acquisition in December 2012; and

$2.9 million at Rockland attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition in December 2012.

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

- $2.5 million at Mamquam resulting from higher maintenance costs due to a scheduled outage and decreased revenues caused by lower water levels.

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Southwest

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

	Three months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Southwest			
Project Adjusted EBITDA	$ 19.0	$ 12.6	51%

Three months ended June 30, 2013 compared with three months ended June 30, 2012

Project Adjusted EBITDA for the three months ended June 30, 2013 increased by $6.4 million or 51% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $7.8 million at Canadian Hills which became commercially operational in December 2012.

This increase was partially offset by decreases in Project Adjusted EBITDA of:

- $1.7 million at Morris attributable to higher maintenance costs, higher fuel expenses, and lower revenues than the comparable period.

	Six months ended June 30,		
	2013	2012	% change 2013 vs. 2012
Southwest			
Project Adjusted EBITDA	$ 35.0	$ 24.7	42%

Six months ended June 30, 2013 compared with six months ended June 30, 2012

Project Adjusted EBITDA for the six months ended June 30, 2013 increased by $10.3 million or 42% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $14.6 million at Canadian Hills which became commercially operational in December 2012; and

- $2.0 million at Gregory attributable to lower maintenance costs, increased revenues, and increased generation.

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

- $4.6 million at Morris attributable to higher maintenance costs, higher fuel expenses, and lower revenues.

Project Adjusted EBITDA for the Southwest segment excludes the Path 15 project which is accounted for as a component of discontinued operations and was sold on April 30, 2013. Project Adjusted EBITDA for Path 15 was $2.8 million and $9.0 million for the three and six months ended June 30, 2013, respectively and $4.4 million and $11.1 million for the three and six months ended June 30, 2012, respectively.

Cash Available for Distribution

The payout ratio associated with the cash dividends declared to shareholders was (165)% and 249% for the three months ended June 30, 2013 and 2012 respectively, and 48% and 89% for the six months ended June 30, 2013 and 2012, respectively. On February 28, 2013, we announced a reduction in the dividend level from a monthly dividend level of Cdn$0.09583 to Cdn$0.03333 commencing with the March 2013 dividend to shareholders of record on March 28, 2013. The payout ratio for the three

months ended June 30, 2013 as compared to the same period in 2012 was negatively impacted by lower operating cash flows as a result of the sale of the Florida Projects and Path 15 in April 2013 and transaction costs incurred related to selling these projects. This was partially offset by reduced cash dividends declared to shareholders as well as the inclusion of operating results from Canadian Hills and Meadow Creek which achieved commercial operations in late December 2012. The payout ratio for the six months ended June 30, 2013 compared to the same period in 2012 was positively impacted by reduced cash dividends declared to shareholders. Due to the timing of numerous working capital adjustments and the cash payments associated with our corporate level interest payments, our payout ratio will fluctuate from quarter to quarter. For example, the interest payments on the $460 million Senior Notes are due semi-annually (May and November) and will impact our payout ratios in the second and fourth quarters.

The table below presents our calculation of Cash Available for Distribution for the three and six months ended June 30, 2013 and 2012, and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

(unaudited) **(in millions of U.S. dollars, except as otherwise stated)**	**Three months ended June 30,** **2013**	 **2012**	**Six months ended June 30,** **2013**	 **2012**
Cash flows from operating activities[1]	$ 7.2	$ 22.9	$ 96.9	$ 89.3
Project-level debt repayments	(7.9)	(6.6)	(10.5)	(9.3)
Purchases of property, plant and equipment	(2.9)	(0.1)	(5.1)	(0.8)
Dividends on preferred shares of a subsidiary company	(3.1)	(3.2)	(6.3)	(6.4)
Cash Available for Distribution[2]	(6.7)	13.0	75.0	72.8
Total cash dividends declared to shareholders	11.0	32.3	36.3	65.1
Payout ratio	(165)%	249%	48%	89%

(1) We reclassified $(15.5) million from cash flows from operations to construction in progress in cash flows used in investing activities in the three months ended March 31, 2013. The reclassification increases Cash Available for Distribution from $66.2 million to $81.7 million and reduced the payout ratio from 38% to 31% for the three months ended March 31, 2013.

(2) Cash Available for Distribution 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.

Consolidated Cash Flows

At June 30, 2013, cash and cash equivalents increased $135.4 million from December 31, 2012 to $195.6 million. The increase in cash and cash equivalents was due to $96.9 million provided by operating activities and $151.3 provided by investing activities offset by $119.3 million of cash used in financing activities. The operating, investing and financing activities include the Florida Projects and Path 15 discontinued operations. There was $6.5 million of cash located at these projects at December 31, 2012.

At June 30, 2012, cash and cash equivalents increased $2.0 million from December 31, 2011 to $62.7 million. The increase in cash and cash equivalents was primarily due to $89.3 million provided by

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operating activities and $117.7 million of cash provided by financing activities, offset by $205.0 million of cash used in investing activities.

	Six months ended June 30, 2013	Six months ended June 30, 2012	$ Change 2013 vs. 2012
Net cash provided by operating activities	$ 96.9	$ 89.3	$ 7.6
Net cash provided by (used in) investing activities	151.3	(205.0)	356.3
Net cash (used in) provided by financing activities	(119.3)	117.7	(237.0)

Operating Activities

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

Cash flow from operating activities increased by $7.6 million for the six months ended June 30, 2013 from the comparable period in 2012. The change from the prior year is primarily attributable to the increases in Project Adjusted EBITDA noted above.

Investing Activities

Cash flow from investing activities includes changes in restricted cash. Restricted cash fluctuates from period to period in part because non-recourse project-level financing arrangements typically require all operating cash flow from the project to be deposited in restricted accounts and then released at the time that principal payments are made and project-level debt service coverage ratios are met. As a result, the timing of principal payments on project-level debt causes significant fluctuations in restricted cash balances, which typically benefits investing cash flow in the second and fourth quarters of the year and decreases investing cash flow in the first and third quarters of the year.

Cash flow provided by (used in) investing activities includes cash used to fund acquisitions and construct development projects in North American markets. Cash flows provided by investing activities for the six months ended June 30, 2013 were $151.3 million compared to cash flows used in investing activities of $205.0 million for the six months ended June 30, 2012. The change is due to a $219.5 million decrease of cash used in construction in progress related to the Piedmont and Canadian Hills projects which have both recently completed construction and achieved commercial operations, partially offset by $148.3 million in cash received for the sale of the Florida Projects and Path 15 and $53.7 million in treasury grant proceeds received for Meadow Creek in the six months ended June 30, 2013.

Financing Activities

Cash used in financing activities for the six months ended June 30, 2013 resulted in a net outflow of $119.3 million compared to a net inflow of $117.7 million for the comparable 2012 period. The change from the prior year is due to a $234.5 million decrease in the proceeds from long-term debt primarily attributable to $176.1 million construction loan proceeds received for the Canadian Hills construction loan in the six months ended June 30, 2012 and a $54.9 million increase in the repayment of project level debt primarily related to Meadow Creek's construction debt paid down with treasury grant proceeds. This was partially offset by an $18.9 million decrease in dividends paid to common shareholders and $44.6 million received in equity contributions from noncontrolling interests at Canadian Hills.

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Liquidity and Capital Resources

(in millions of U.S. dollars, except as otherwise stated)	June 30, 2013	December 31, 2012	June 30, 2013[(1)]
Cash and cash equivalents	$ 195.6	$ 60.2	$ 120.6
Restricted cash	40.1	28.6	115.1
Total	235.7	88.8	235.7
Senior credit facility availability	217.5	120.1	67.5
Total liquidity	$ 453.2	$ 208.9	$ 303.2

(1) This column represents a pro forma liquidity as of June 30, 2013 pursuant to the August 2, 2013 amended credit facility as discussed below.

Overview

Our primary sources of liquidity are distributions from our projects and availability of letters of credit under our senior credit facility. Substantially all of the cash received from project distributions is used to pay dividends to our common and preferred shareholders and interest on our outstanding convertible debentures, senior notes and other corporate-level debt. Our liquidity depends in part on our ability to successfully enter into new PPAs at facilities where PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from August 2013 to 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, which may reduce the cash received from project distributions. 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.

We do not expect any material unusual requirements for cash outflows during the remainder of 2013 for capital expenditures or other required investments. In addition, as of August 5, 2013, there are no debt instruments with maturities in 2013. In April 2013, we utilized a portion of the net proceeds received from the sale of the Florida Projects to fully repay our senior credit facility which had an outstanding balance of $64.1 million at close of the transaction. At June 30, 2013, our senior credit facility was undrawn and the applicable margin was 2.75%. As of June 30, 2013, $82.5 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. We must meet certain financial covenants under the terms of our senior credit facility, which are generally based on ratios as described in Note 5 to the consolidated financial statements in this Quarterly Report on Form 10-Q for the three and six months ended June 30, 2013 and in Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2012.

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 the next 12 months.

On August 2, 2013 we entered into the amended credit facility. The most significant changes to the senior credit facility include the following:

- a decrease in capacity from $300 million to $150 million, all of which may be utilized for letters of credit (as compared to the previous $200 million that could have been utilized for letters of credit) and a sublimit of $25 million which may be utilized for other borrowings;

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- a requirement to cash collateralize outstanding letters of credit in an amount equal to the excess above $125 million if the aggregate amount of letters of credit and borrowings outstanding under the amended facility exceeds $125 million;

- a requirement to maintain at all times unrestricted cash and cash equivalents of at least $75 million (inclusive of any cash collateral provided as described above), which amounts shall be pledged to the lenders as security for the amended credit facility;

- an amendment to the maximum permissible Consolidated Total Net Debt to Consolidated EBITDA ratio (each as defined in the amended credit facility) to 7.75 to 1.00 (as compared to a prior ratio of 7.50 to 1.00 declining to 7.00 to 1.00 over time);

- an amendment to the minimum permissible Consolidated EBITDA to Consolidated Interest Expense (each as defined in the amended credit facility) ratio to 1.60 to 1.00 (as compared to a prior ratio of 2.25 to 1.00);

- a requirement to pay a commitment fee of between 0.75% and 1.75% per year based on a percentage of the amount committed under the amended credit facility, which fee varies based on our unsecured debt rating (currently, the applicable commitment fee is 1.50%); and

- an amendment to the maturity date from November 4, 2015 to March 4, 2015.

Among other restrictions set forth in the amended credit facility, we are restricted from paying cash dividends to our shareholders if we do not comply with the financial covenants specified above. The amended credit facility is secured by pledges of certain assets and interests in certain subsidiaries. The senior credit facility contained customary representations, warranties, terms and conditions, and covenants, certain of which were amended in the amended credit facility. The amended covenants limit our ability to, among other things, incur additional indebtedness, merge or consolidate with others, make acquisitions, change our business and sell or dispose of assets. These amended covenants also include limitations on investments, limitations on dividends and other restricted payments, limitations on entering into certain types of restrictive agreements, limitations on transactions with affiliates and limitations on the use of proceeds from the amended credit facility. Specifically, under the amended credit facility, we are only permitted to make voluntary prepayments or repurchases of the $150 million in principal amount of 5.87% Senior Guaranteed Notes, Series A, due August 15, 2015 that were issued by our subsidiary Atlantic Power (US) G.P., except that under the amended credit facility we may also voluntarily prepay or repurchase any of our outstanding debt (including for these purposes subsidiary debt guaranteed by us) from the proceeds of debt permitted to be incurred to refinance that outstanding debt or during the 60-day period preceding the maturity of that outstanding debt. Under the senior credit facility, we had the right generally to repurchase substantially more of our outstanding debt issuances, subject to the satisfaction of certain conditions. Under the amended credit facility, the lenders also consented to (i) our previously announced sale of Delta-Person and (ii) the sale of AP Onondaga, LLC, Onondaga Renewables, LLC and their property.

Borrowings under the amended credit facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the US Prime Rate, the Eurocurrency LIBOR Rate or the Cdn. Prime Rate (each as defined in the amended credit facility), as applicable, plus a margin of between 1.75% and 4.75% that varies based on our unsecured debt rating. Currently, the applicable margin for loans bearing interest at the Eurocurrency LIBOR Rate and for the outstanding letters of credit is 4.25%. The foregoing summary is qualified in its entirety by reference to the amended credit facility which has been filed as an exhibit to our Current Report on Form 8-K on August 5, 2013.

We expect to meet covenants under the amended credit facility for the next twelve months. As of August 5, 2013, we were in compliance with these covenants.

We must also meet certain financial covenants under the terms of our 9% senior unsecured notes, including a Consolidated EBITDA to Consolidated Interest Expense ratio. As of August 5, 2013, we were in compliance with these ratios. After further review of our currently forecasted results and taking into account implications of our recently amended credit facility, we currently believe that it is likely, during the third quarter of 2014, that we may not meet the provision requiring that our Fixed Charge Coverage Ratio (included in the restricted payments covenant in the indenture governing our 9% senior unsecured notes) be no less than 1.75 to 1.00. If we are not in compliance with this covenant, dividend payments in the aggregate must not exceed the basket provision in such covenant of the greater of $50 million and 2% of Consolidated Net Assets (approximately $68 million at June 30, 2013). Based on the current dividend level, we believe that this basket would permit the payment of the current dividend level for at least 12 months beyond a determination of non-compliance. Additionally, during any potential period of non-compliance, we would be permitted under other basket provisions of the indenture to borrow up to $350 million under a revolving credit facility and incur additional indebtedness of up to 15% of Consolidated Net Assets (approximately $500 million at June 30, 2013). Dividends or borrowings made in compliance with such basket provisions would not trigger an event of default under such indenture or a cross-default with respect to our other indebtedness.

We are currently considering various initiatives to maintain compliance with such covenants, including potentially, among other things, debt reduction, expense reduction and asset optimization. Because we are at the preliminary stages of considering initiatives, we cannot provide assurance that any of these potential initiatives will be successful.

Defined terms used in the foregoing discussion are as defined in the indenture governing the 9% senior unsecured notes and the foregoing summary is qualified in its entirety by reference to such indenture, which has been filed as an exhibit to our Annual Report on Form 10-K.

Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2013:

	Interest Rates	Total Remaining Principal Repayments	2013	2014	2015	2016	2017	Thereafter
Atlantic Power Corporation Notes	9.0%	$ 460.0	$	$	$	$	$	$ 460.0
Atlantic Power US (GP) Note	6.0%	150.0			150.0			
Atlantic Power US (GP) Note	5.9%	75.0					75.0	
Atlantic Power Income LP Note	6.0%	199.7						199.7
Convertible Debenture	6.5%	42.6		42.6				
Convertible Debenture	6.3%	64.1					64.1	
Convertible Debenture	5.6%	76.5					76.5	
Convertible Debenture	5.8%	130.0						130.0
Convertible Debenture	6.0%	95.1						95.1
Total Corporate Debt		$ 1,293.0	$	$ 42.6	$ 150.0	$	$ 215.6	$ 884.8

Project-Level Debt

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, 2013 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. 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. As of June 30, 2013, the covenants at Delta-Person, for which we have entered into an agreement to sell and Gregory which was sold on August 7, 2013, are temporarily preventing those projects from making cash distributions to us. All project-level debt is non-recourse to us and substantially all of the principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly owned subsidiary.

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The range of interest rates presented represents the rates in effect at June 30, 2013. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2013	2014	2015	2016	2017	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.4%	$ 32.0	$ 1.5	$ 5.0	$ 5.8	$ 6.0	$ 6.3	$ 7.4
Piedmont[1]	3.8% 5.2%	126.1	53.6	4.5	4.5	3.4	2.9	57.2
Cadillac	6.0% 8.0%	36.6	1.2	2.0	3.9	2.5	3.0	24.0
Rockland	6.4% 6.7%	85.8	0.4	1.5	1.8	1.9	2.2	78.0
Ridgeline	5.5% 5.9%	0.3					0.3	
Curtis Palmer[2]	5.9%	190.0		190.0				
Meadow Creek	5.1% 5.6%	171.4	1.6	4.9	4.6	5.3	5.3	149.7
Total Consolidated Projects		642.2	58.3	207.9	20.6	19.1	20.0	316.3
Equity Method Projects:								
Chambers	0.6% 7.2%	46.7	5.5	0.9	0.2	0.1		40.0
Delta-Person[3]	1.9%	7.1	0.6	1.3	1.4	1.5	1.1	1.2
Gregory[4]	2.3% 7.7%	9.6	1.0	2.1	2.2	2.4	1.9	
Goshen	3.0% 7.1%	24.6	0.3	0.4	0.5	0.7	0.9	21.8
Idaho Wind	5.6%	48.0	1.3	2.4	2.6	2.5	2.7	36.5
Total Equity Method Projects		136.0	8.7	7.1	6.9	7.2	6.6	99.5
Total Project-Level Debt		$ 778.2	$ 67.0	$ 215.0	$ 27.5	$ 26.3	$ 26.6	$ 415.8

(1) As of June 30, 2013 the balance of $126.1 million on the Piedmont debt was funded by a $51.0 million bridge loan and an $82.0 million construction loan ($75.1 million at June 30, 2013) that is expected to convert to a term loan in the third quarter of 2013. On April 19, 2013, Piedmont achieved commercial operations and submitted an application under the 1603 federal grant program to recover approximately 30% of its capital cost. The grant application was approved and we received a $49.5 million grant from the U.S. Treasury in July 2013. Upon receipt of the grant, we repaid in full the $51.0 million bridge loan with the proceeds of the grant and a $1.5 million contribution from Atlantic Power to cover the shortfall resulting from the federal sequester on spending. We expect to commence the repayment of the $75.1 million balance of the construction loan in 2013.

(2) The Curtis Palmer Notes are not considered non-recourse project-level debt as these notes are guaranteed by the Partnership. Interest expense associated with the Curtis Palmer notes are recorded as a component of project income.

(3) We have entered into an agreement to sell our interest in the Delta-Person project with plans to close the sale in the fourth quarter of 2013.

(4) The Gregory project was sold on August 7, 2013.

Uses of Liquidity

Our requirements for liquidity and capital resources, other than operating our projects, consist primarily of dividend payments to our common shareholders and preferred shareholders of a subsidiary company, principal and interest on our outstanding convertible debentures, Senior Notes and other corporate and project level debt and capital expenditures, including major maintenance and business development costs. 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.

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.

We expect to reinvest approximately $30 to $35 million in 2013 in our project portfolio in the form of capital expenditures and major maintenance expenses, of which we have already reinvested approximately $23.3 million as of June 30, 2013. As explained above, this investment is 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 level in 2012 or the projected level in 2013 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

In all cases, scheduled maintenance outages during the three and six months ended June 30, 2013 and 2012 occurred at such times that did not adversely 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, 2013, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 6 to the consolidated financial statements, *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 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, 2012. 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 also exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. As of August 5, 2013, we have entered into natural gas swaps in order to effectively fix approximately 74% of our share of the expected natural gas purchases at the project during 2014 and 2015 and approximately 38% of our share of the expected natural gas purchases at the project during 2016 and 2017.

In April and June 2013, we entered into contracts for the purchase of natural gas beginning on November 1, 2013 and expiring on March 31, 2014 for the Tunis project in order to fix approximately 50% of the expected natural gas purchase requirement during that period. Adjusted for these transactions, projected annual cash distributions at Tunis in 2013 would change by approximately $1.6 million per $1.00/MMBtu change in the price of natural gas based on the current level of natural gas volumes used by the project.

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 projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers and Morris projects. At Chambers, 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 2013, projected cash distributions at Chambers would change by approximately $0.6 million per 10% change in the spot price of electricity based on a forecasted level of approximately $42/MWh and certain other assumptions. Our equity investment in the Chambers project is 40%. At Morris, the facility can sell approximately 100MW 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 2013, projected cash distributions at Morris would change by approximately $1.0 million per 20% change in the spot price of electricity based on the current level of approximately 300,000 MWh grid sales and all other variables being held constant. We own 100% of the Morris project. See Item 1A. "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 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, 2012.

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 projects may not be able to secure a new agreement and could be exposed to sell power at spot market prices. 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, 2012. It is possible that subsequent PPAs or the spot markets 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 and interest on corporate level long-term debt and convertible debentures

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predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on future payments of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 71% of our expected dividend, long-term debt and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At June 30, 2013, the forward contracts consist of (1) monthly purchases through the end of July 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$34.9 million at an average exchange rate of Cdn$1.10 per U.S. dollar. It is our intention to periodically consider extending or terminating these forward contracts. In April 2013, we terminated various foreign currency forward contracts with expiration dates through June 2015 assumed in our acquisition of the Partnership, resulting in proceeds of $9.4 million.

The 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.

The following table contains the components of recorded foreign exchange (gain) loss for the three and six months ended June 30, 2013 and 2012 (in millions):

	Three months ended June 30,		**Six months ended June 30,**	
	2013	**2012**	**2013**	**2012**
Unrealized foreign exchange (gain) loss:				
Convertible debentures and other	$ (16.5)	$ (8.8)	$ (27.5)	$ (1.1)
Forward contracts	12.8	7.7	18.8	12.9
	(3.7)	(1.1)	(8.7)	11.8
Realized foreign exchange gains on forward contract settlements	(10.8)	(3.1)	(13.3)	(15.0)
Total foreign exchange gain	$ (14.5)	$ (4.2)	$ (22.0)	$ (3.2)

The U.S dollar to Canadian dollar exchange rate was 1.0518 at June 30, 2013. The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of June 30, 2013 (in millions):

Convertible debentures denominated in Canadian dollars, at carrying value	$ (25.3)