ATLANTIC POWER CORP
Form 10-Q
May 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 March 31, 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 (State or other jurisdiction of incorporation or organization)	**55-0886410** (I.R.S. Employer Identification No.)
One Federal Street, 30th Floor **Boston, MA** (Address of principal executive offices)	**02110** (Zip code)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

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

Large accelerated filer 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 May 6, 2013 was 119,817,192.

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ATLANTIC POWER CORPORATION

FORM 10-Q

THREE MONTHS ENDED MARCH 31, 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)

	March 31, 2013 (unaudited)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 85.7	$ 60.2
Restricted cash	43.5	28.6
Accounts receivable	78.4	58.5
Current portion of derivative instruments asset (Notes 5 and 6)	9.0	9.5
Inventory	20.0	16.9
Prepayments and other current assets	16.5	13.4
Security deposits	1.2	19.0
Assets held for sale (Note 10)	346.8	351.4
Refundable income taxes	3.6	4.2
Total current assets	604.7	561.7
Property, plant, and equipment, net of accumulated depreciation of $104.2 million and $79.2 million at March 31, 2013 and December 31, 2012, respectively	2,020.0	2,055.5
Equity investments in unconsolidated affiliates	411.1	428.7
Other intangible assets, net of accumulated amortization of $92.3 million and $76.9 million at March 31, 2013 and December 31, 2012, respectively	505.7	524.9
Goodwill	334.7	334.7
Derivative instruments asset (Notes 5 and 6)	5.8	11.1
Other assets	57.4	86.1
Total assets	$ 3,939.4	$ 4,002.7
Liabilities		
Current liabilities:		
Accounts payable	$ 14.4	$ 17.8
Accrued interest	30.0	19.0
Other accrued liabilities	43.0	73.7
Revolving credit facility (Note 4)	64.1	67.0
Current portion of long-term debt (Note 4)	121.7	121.2
Current portion of derivative instruments liability (Notes 5 and 6)	25.9	33.0
Dividends payable	3.9	11.5
Liabilities associated with assets held for sale (Note 10)	205.3	189.0
Other current liabilities	1.8	3.3
Total current liabilities	510.1	535.5
Long-term debt (Note 4)	1,474.1	1,459.1
Convertible debentures	418.2	424.2
Derivative instruments liability (Notes 5 and 6)	110.2	118.1

Deferred income taxes		159.1		164.0
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $5.4 million and $4.4 million at March 31, 2013 and December 31, 2012, respectively		42.5		44.0
Other non-current liabilities		70.0		71.4
Commitments and contingencies (Note 13)				
Total liabilities		2,784.2		2,816.3
Equity				
Common shares, no par value, unlimited authorized shares; 119,783,366 and 119,446,865 issued and outstanding at March 31, 2013 and December 31, 2012, respectively (Note 11)		1,285.3		1,285.5
Preferred shares issued by a subsidiary company (Note 11)		221.3		221.3
Accumulated other comprehensive income (loss)		(2.4)		9.4
Retained deficit		(583.5)		(565.2)
Total Atlantic Power Corporation shareholders' equity		920.7		951.0
Noncontrolling interests (Note 11)		234.5		235.4
Total equity		1,155.2		1,186.4
Total liabilities and equity	$	3,939.4	$	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 March 31, 2013	Three months ended March 31, 2012
Project revenue:		
Energy sales	$ 69.0	$ 60.0
Energy capacity revenue	44.8	37.0
Other	26.4	21.7
	140.2	118.7
Project expenses:		
Fuel	49.6	46.2
Operations and maintenance	28.3	24.7
Development	1.7	
Depreciation and amortization	41.3	26.5
	120.9	97.4
Project other income (expense):		
Change in fair value of derivative instruments (Notes 5 and 6)	12.6	(57.2)
Equity in earnings of unconsolidated affiliates (Note 3)	7.2	2.9
Interest, net	(8.0)	(4.0)
	11.8	(58.3)
Project income (loss)	31.1	(37.0)
Administrative and other expenses (income):		
Administration	8.3	7.7
Interest, net	25.9	22.0
Foreign exchange loss (gain) (Note 6)	(7.5)	1.0
	26.7	30.7
Income (loss) from continuing operations before income taxes	4.4	(67.7)
Income tax benefit (Note 7)	(2.5)	(16.9)
Income (loss) from continuing operations	6.9	(50.8)
Income from discontinued operations, net of tax (Note 10)	0.9	11.6
Net income (loss)	7.8	(39.2)
Net loss attributable to noncontrolling interests	(1.9)	(0.1)
Net income attributable to preferred shares dividends of a subsidiary company	3.2	3.2
Net income (loss) attributable to Atlantic Power Corporation	$ 6.5	$ (42.3)
Basic earnings (loss) per share: (Note 9)		
Income (loss) from continuing operations attributable to Atlantic Power Corporation	$ 0.04	$ (0.47)
Income from discontinued operations, net of tax	0.01	0.10

Net income (loss) attributable to Atlantic Power Corporation	$	0.05	$	(0.37)
Diluted earnings (loss) per share: (Note 9)				
Income (loss) from continuing operations attributable to Atlantic Power Corporation	$	0.04	$	(0.47)
Income from discontinued operations, net of tax		0.01		0.10
Net income (loss) attributable to Atlantic Power Corporation	$	0.05	$	(0.37)
Weighted average number of common shares outstanding: (Note 9)				
Basic		119.5		113.6
Diluted		119.9		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 March 31, 2013	Three months ended March 31, 2012
Net income (loss)	$ 7.8	$ (39.2)
Other comprehensive income (loss), net of tax:		
Net amount reclassified to earnings	0.3	0.3
Net unrealized losses on derivatives	0.3	0.3
Foreign currency translation adjustments	(12.1)	17.2
Other comprehensive (loss) income, net of tax	(11.8)	17.5
Comprehensive loss	(4.0)	(21.7)
Less: Comprehensive income attributable to noncontrolling interests	1.3	3.1
Comprehensive loss attributable to Atlantic Power Corporation	$ (5.3)	$ (24.8)

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)

	Three months ended March 31, 2013	Three months ended March 31, 2012
Cash flows from operating activities:		
Net income (loss)	$ 7.8	$ (39.2)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	49.1	36.5
Reserve related to sale of discontinued operations	27.5	
Long-term incentive plan expense	0.3	1.1
Equity in earnings from unconsolidated affiliates	(7.2)	(2.9)
Distributions from unconsolidated affiliates	8.9	0.3
Unrealized foreign exchange (gain) loss	(5.0)	12.9
Change in fair value of derivative instruments	(21.1)	58.1
Change in deferred income taxes	(4.1)	(17.7)
Change in other operating balances		
Accounts receivable	(4.6)	19.5
Inventory	0.9	0.8
Prepayments, refundable income taxes and other assets	39.7	(14.9)
Accounts payable	(8.0)	6.6
Accruals and other liabilities	(10.0)	5.5
Cash provided by operating activities	74.2	66.6
Cash flows used in investing activities:		
Change in restricted cash	(18.7)	(6.4)
Biomass development costs		(0.1)
Construction in progress	(9.7)	(163.5)
Purchase of property, plant and equipment	(2.2)	(0.7)
Cash used in investing activities	(30.6)	(170.7)
Cash flows (used in) provided by financing activities:		
Proceeds from project-level debt	20.8	184.2
Repayment of project-level debt	(2.6)	(2.7)
Offering costs related to tax equity	(0.6)	
Payments for revolving credit facility borrowings	(2.9)	(8.0)
Proceeds from revolving credit facility borrowings		22.8
Equity contribution from noncontrolling interest	2.0	
Deferred financing costs		(10.2)
Dividends paid	(36.3)	(36.0)
Cash (used in) provided by financing activities	(19.6)	150.1
Net increase in cash and cash equivalents	24.0	46.0
Less cash at discontinued operations	(5.0)	
Cash and cash equivalents at beginning of period at discontinued operations	6.5	
Cash and cash equivalents at beginning of period	60.2	60.6
Cash and cash equivalents at end of period	$ 85.7	$ 106.6

Supplemental cash flow information				
Interest paid	$	17.1	$	18.0
Income taxes paid, net	$	1.4	$	0.6
Accruals for construction in progress	$	1.6	$	3.7

See accompanying notes to consolidated financial statements.

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 March 31, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,965 megawatts ("MW") in which our aggregate ownership interest is approximately 2,046 MW. These totals exclude Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") and the Path 15 transmission line, including Atlantic Path 15 Transmission, LLC, Atlantic Holdings Path 15, LLC and Atlantic Path 15, LLC (collectively, "Path 15"), each of which are designated as held for sale at March 31, 2013, our 17.1% interest in Gregory Power Partners, L.P. ("Gregory") for which we entered into an agreement to sell in April 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-eight operational power generation projects across ten states in the United States and two provinces in Canada. In addition, we have one 53 MW biomass project in Georgia, which 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, free of charge, on our website 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.

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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)

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of March 31, 2013, the results of operations, comprehensive income and our cash flows for the three month periods ended March 31, 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.

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

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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)

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, 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 ("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.

On January 1, 2012, we adopted changes issued by the FASB to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in shareholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We elected to present the two-statement option. Other than the change in presentation, the adoption of these changes had no impact on the consolidated financial statements.

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 litigation and judicial rulings. These changes become effective for us on January 1, 2014. We have

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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)

determined that the adoption of these changes will not have an 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 an 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. On May 2, 2013, we sold our tax equity ownership in Canadian Hills to an institutional investor and received net cash proceeds of $42.1 million. The cash proceeds will be held for general corporate purposes and to invest in future accretive growth opportunities. The project's outstanding construction loan was repaid by the proceeds from these tax equity investors, decreasing the project's short-term debt by $265 million as of December 31, 2012. Canadian Hills has no debt at March 31, 2013.

The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheets at March 31, 2013 and December 31, 2012. 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").

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestments (Continued)

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 $272.8 million including working capital adjustments. We expect to receive net cash proceeds for our ownership interest of approximately $33.7 million in the aggregate, after repayment of project-level debt and transaction expenses. We intend to use the net proceeds from the sale for general corporate purposes and to invest in future accretive growth opportunities. We expect the sale of Gregory to close in the third quarter of 2013.

(b)
Auburndale, Lake and Pasco

On January 30, 2013, we entered into a purchase and sale agreement for the sale of our 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 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 Florida Projects are accounted for as assets held for sale in the consolidated balance sheets at March 31, 2013 and December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the three months ended March 31, 2013 and 2012. See Note 10, *Assets held for sale*, for further information.

(c)
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 held for general corporate purposes and to invest in future accretive growth opportunities. In April 2013, we recorded a gain on sale of approximately $7.0 million. All project level debt issued by Path 15, totaling $137.2 million as of March 31, 2013, transferred with the sale. Path 15 is accounted for as an asset held for sale in the consolidated balance sheets at March 31, 2013 and December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the three months ended March 31, 2013 and 2012. See Note 10, *Assets held for sale*, for further information.

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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Equity method investments

The following summarizes the operating results for the three months ended March 31, 2013 and 2012, respectively, for earnings in our equity method investments:

	Three months ended March 31,	
(in millions)	**2013**	**2012**
Project revenue		
Chambers	$ 13.2	$ 13.2
Other	39.4	40.1
	52.6	53.3
Project expenses		
Chambers	9.6	9.8
Other	33.7	35.7
	43.3	45.5
Project other expenses		
Chambers	(0.6)	(1.2)
Other	(1.5)	(3.7)
	(2.1)	(4.9)
Project income		
Chambers	3.0	2.2
Other	4.2	0.7
	7.2	2.9

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt

Long-term debt consists of the following:

(in millions)	March 31, 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)	206.7	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	32.7	33.5	7.4%
Cadillac term loan, due 2025	37.2	37.8	6.0% 8.0%
Piedmont construction loan, due 2013	127.6(1)	127.4	Libor plus 3.5%
Meadow Creek term loan, due 2030	229.3(2)	208.7	1.3% 5.1%
Rockland term loan, due 2031	86.5	86.5	6.4%
Other long-term debt	0.8	0.3	5.5% 6.7%
Less current maturities	(121.7)	(121.2)	
Total long-term debt	$ 1,474.1	$ 1,459.1	

Current maturities consist of the following:

	March 31, 2013	December 31, 2012	Interest Rate
Current Maturities:			
Epsilon Power Partners term facility, due 2019	$ 3.5	$ 3.0	7.4%
Cadillac term loan, due 2025	2.3	2.4	6.0% 8.0%
Piedmont construction loan, due 2013	55.1(1)	55.1	Libor plus 3.5%
Meadow Creek term loan, due 2013	59.5(2)	59.5	1.3% 5.1%
Rockland term loan, due 2031	1.2	1.2	6.4%
Other current maturities	0.1		5.5% 6.7%
Total current maturities	$ 121.7	$ 121.2	

(1) The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan, a portion of which we expect to repay with the proceeds from the stimulus grant expected to be received from the U.S. Treasury, and an $82.0 million construction loan that we expect to convert to a term loan. While we fully expect the construction loan to convert to a term loan in second quarter 2013 based on the project meeting specified milestone requirements, if it does not, we have the option of amending or refinancing the construction loan or infusing additional equity into the project. On April 19, 2013, Piedmont achieved commercial operations and expects to submit an application under the 1603 federal grant program within 60 days from this date to recover approximately 30% of its capital cost, subject to the potential impact of the federal sequester on spending which we estimate to be an approximate $2.0 million shortfall. The $51.0 million bridge loan is expected to be repaid by end of third quarter of 2013 and repayment of the expected $82.0 million term loan would commence in 2013.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt (Continued)

(2) Meadow Creek debt consists of $172.8 million drawn on a construction loan which converted to a term loan in March 2013 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 lower project cost versus budget.

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. At March 31, 2013, Delta-Person and Gregory had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us. None of these covenant failures create an event of default or result in the non-recourse debt being callable at March 31, 2013.

Senior Credit Facility

We have a senior credit facility of $300.0 million on a senior secured basis (the "senior credit facility"), $200.0 million of which may be utilized for letters of credit. Borrowings under the facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the U.S. Prime Rate, the London Interbank Offered Rate or the Canadian Prime Rate, as applicable, plus an applicable margin of between 0.8% and 3.0% that varies based on our corporate credit rating. The senior credit facility matures on November 4, 2015.

On November 2, 2012, we amended the senior credit facility in order to change certain financial and leverage ratio covenants. These changes involved the better accommodation of construction stage projects with no historical financial performance, the better accommodation of the possibility of certain asset sales, including our Florida Projects, by waiving a material disposition covenant and permitting inclusion of the disposed assets' trailing twelve months EBITDA for covenant calculations, and the better accommodation of the same possible asset sales by temporarily modifying the Total Leverage Ratio. See Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2012 for further information.

At March 31, 2013, $64.1 million has been drawn under the senior credit facility and the applicable margin was 2.8%. The balance was repaid in full on April 15, 2013 with a portion of the proceeds from the sale of the Florida Projects. As of March 31, 2013, $111.6 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. On April 30, 2013, letters of credit issued, but not drawn, were reduced to $82.5 million resulting from the sale of the Florida Projects and Path 15.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. 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 March 31, 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.

	March 31, 2013			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:				
Cash and cash equivalents	$ 85.7	$	$	$ 85.7
Restricted cash	43.5			43.5
Derivative instruments asset		14.8		14.8
Total	$ 129.2	$ 14.8	$	$ 144.0
Liabilities:				
Derivative instruments liability	$	$ 136.1	$	$ 136.1
Total	$	$ 136.1	$	$ 136.1

	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 March 31, 2013, the credit valuation adjustments resulted in a $16.7 million net increase in fair value, which consists of

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Fair value of financial instruments (Continued)

a $0.9 million pre-tax gain in other comprehensive income and a $15.8 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 $1.1 million pre-tax gain in other comprehensive income and a $13.8 million gain in change in fair value of derivative instruments, offset by a $3.6 million related to interest rate swaps assumed in the acquisition of Ridgeline.

6. 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.

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 December 31, 2012. Changes in the fair market value of the contract are recorded in the consolidated statements 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Derivative instruments and hedging activities (Continued)

64% 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 25% 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).

The Piedmont Green Power project ("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%. 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 5.1%. 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.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Derivative instruments and hedging activities (Continued)

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 agreement effectively converted the floating rate debt to a fixed interest rate of 5.1% from December 31, 2012 to December 31, 2024. From December 2024 until the maturity of the debt in December 2030, the fixed rate of the swap is 6.7%. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Meadow Creek's term loan. 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 we generate cash flow in U.S. dollars and Canadian dollars but pay dividends to shareholders and interest on our Canadian dollar denominated convertible debentures and long-term debt predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future payments of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 112% of our expected dividend and convertible debenture interest payments through 2015. Changes in the fair value of the forward contracts more than offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. At March 31, 2013, the forward contracts consist of (1) monthly purchases through the end of 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 Atlantic Power Limited Partnership (formerly, Capital Power Income L.P.) (the "Partnership") with various expiration dates through December 2015 to purchase a total of Cdn$99.7 million at an average exchange rate of Cdn$1.14 per U.S. dollar. It is our intention to periodically consider extending the length or terminating these forward contracts. The foreign currency forward contracts are not designated as hedges, and changes in their market value are recorded in the consolidated statements of operations.

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. Subsequent to the termination, cash flows from our projects that generate Canadian dollars and our remaining forward contracts to purchase Canadian dollars at a fixed rate, hedge an average of approximately 75% of our expected dividend, Canadian dollar denominated long-term debt and convertible debenture interest payments through 2015.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Derivative instruments and hedging activities (Continued)

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 March 31, 2013 and December 31, 2012:

	Units	March 31, 2013	December 31, 2012
Natural gas swaps	Natural Gas (MMBtu)	8.6	10.6
Gas purchase agreements	Natural Gas (GJ)	46.8	49.8
Interest rate swaps	Interest (US$)	170.6	172.0
Foreign currency forwards	Cdn$	153.7	176.6

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 March 31, 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:

	March 31, 2013	
	Derivative Assets	Derivative Liabilities
	(in millions)	
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.3
Interest rate swaps long-term		4.7
Total derivative instruments designated as cash flow hedges		6.0
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		9.6
Interest rate swaps long-term	0.4	21.7
Foreign currency forward contracts current	8.9	0.1
Foreign currency forward contracts long-term	5.7	0.1
Natural gas swaps current	0.2	0.3
Natural gas swaps long-term	0.2	3.4
Gas purchase agreements current		14.7
Gas purchase agreements long-term		80.8
Total derivative instruments not designated as cash flow hedges	15.4	130.7
Total derivative instruments	$ 15.4	$ 136.7

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. 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:

For the three months ended March 31, 2013	Interest Rate Swaps	Natural Gas Swaps (in millions)	Total
Accumulated OCI balance at December 31, 2012	$ (1.5)	$ 0.1	$ (1.4)
Realized from OCI during the period	0.3		0.3
Accumulated OCI balance at March 31, 2013	$ (1.2)	$ 0.1	$ (1.1)

For the three months ended March 31, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2011	$ (1.7)	$ 0.3	$ (1.4)
Realized from OCI during the period	0.3		0.3
Accumulated OCI balance at March 31, 2012	$ (1.4)	$ 0.3	$ (1.1)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Derivative instruments and hedging activities (Continued)

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 March 31, 2013	Three months ended March 31, 2012
Gas purchase agreements	Fuel	$ 16.3	$ 10.8
Foreign currency forwards	Foreign exchange loss (gain)	(2.5)	(11.9)
Interest rate swaps	Interest, net	2.6	1.1

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 March 31, 2013	Three months ended March 31, 2012
Natural gas swaps	Change in fair value of derivatives	$ (0.4)	$ 0.9
Gas purchase agreements	Change in fair value of derivatives	(8.1)	57.9
Interest rate swaps	Change in fair value of derivatives	(4.1)	(1.6)
Total change in fair value of derivative instruments		$ (12.6)	$ 57.2
Foreign currency forwards	Foreign exchange loss (gain)	$ 6.0	$ 9.2

7. Income taxes

Income tax benefit from continuing operations for the three months ended March 31, 2013 was $2.5 million. The difference between the actual tax benefit of $2.5 million for the three months ended March 31, 2013 and the expected income tax expense of $1.1 million, based on the Canadian enacted statutory rate of 25%, is primarily due to $1.8 million related to operating projects in higher tax rates in various tax jurisdictions, $2.3 million in foreign exchange and $2.4 million in other permanent differences, partially offset by a $2.9 million change in the valuation allowance.

	Three months ended March 31, 2013	Three months ended March 31, 2012
Current income tax expense	$ 2.0	$ 1.4
Deferred tax benefit	(4.5)	(18.3)
Total income tax benefit	$ (2.5)	$ (16.9)

As of March 31, 2013, we have recorded a valuation allowance of $118.2 million. This amount is comprised primarily of provisions against available 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Income taxes (Continued)

that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

8. Employee incentive programs

Long-Term Incentive Program

The following table summarizes the changes in LTIP notional units during the three months ended March 31, 2013:

(Units in thousands)	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2012	492,535	$ 13.9
Granted	482,384	4.9
Additional units from dividends	9,906	13.8
Forfeited	(42,000)	12.3
Vested	(200,697)	13.6
Outstanding at March 31, 2013	742,128	$ 8.2

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. 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 three months ended March 31, 2013 was $0.9 million.

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 March 31, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
Weighted average risk free rate of return	0.1%	0.1 0.3%
Dividend yield	8.0%	10.1%
Expected volatility Atlantic Power	48.6%	22.5%
Expected volatility peer companies	11.9 72.8%	11.9 97.1%
Weighted average remaining measurement period	0.9 years	1.4 years

9. 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)

9. 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 months ended March 31, 2013 and 2012:

	Three months ended March 31,	
	2013	**2012**
Numerator:		
Income (loss) from continuing operations attributable to Atlantic Power Corporation	$ 5.6	$ (53.9)
Income from discontinued operations, net of tax	0.9	11.6
Net loss attributable to Atlantic Power Corporation	$ 6.5	$ (42.3)
Denominator:		
Weighted average basic shares outstanding	119.5	113.6
Dilutive potential shares:		
Convertible debentures	27.7	13.3
LTIP notional units	0.4	0.5
Potentially dilutive shares	147.6	127.4
Diluted loss per share from continuing operations attributable to Atlantic Power Corporation	$ 0.04	$ (0.47)
Diluted earnings per share from discontinued operations	0.01	0.10
Diluted loss per share attributable to Atlantic Power Corporation	$ 0.05	$ (0.37)

Potentially dilutive shares from convertible debentures have been excluded from fully diluted shares for the three months ended March 31, 2013 because their impact would be anti-dilutive and potentially dilutive shares from convertible debentures and LTIP notional units have been excluded from fully diluted shares for the three months ended March 31, 2012 because their impact would be anti-dilutive.

10. Assets held for sale

Path 15 and the Florida Projects have been classified as assets held for sale based on our intention to sell the projects within the next twelve months. We approved a plan to sell these assets prior to December 31, 2012. Accordingly, the assets and liabilities of Path 15 and the Florida Projects have been classified separately as held for sale in the consolidated balance sheets at March 31, 2013 and December 31, 2012 and the projects' net income is recorded as income from discontinued operations, net of tax in the statements of operations for the three months ended March 31, 2013 and 2012. The Florida Projects and Path 15 sales closed on April 12, 2013 and April 30, 2013, respectively.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Assets held for sale (Continued)

We recorded a $27.5 million reserve related to the sale of the Florida Projects that is included in liabilities associated with assets held for sale on the consolidated balance sheets at March 31, 2013 and in income from discontinued operations on the consolidated statements of operation for the three months ended March 31, 2013. The reserve was recorded as a prepayment of the closing price of the sale transaction resulting from the cash distributions we received from the Florida Projects during the three months ended March 31, 2013.

The following tables summarize the revenue, income from operations, and income tax expense of Path 15, Auburndale, Lake, and Pasco for the three months ended March 31, 2013 and 2012 as well as the assets and liabilities held for sale at March 31, 2013 and December 31, 2012:

(in millions)	Three months ended March 31, 2013	Three months ended March 31, 2012
Revenue	$ 63.2	$ 49.0
Income from operations of discontinued businesses	1.3	12.2
Income tax expense	0.4	0.6
Income from operations of discontinued businesses, net of tax	$ 0.9	$ 11.6

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Assets held for sale (Continued)

Basic and diluted earnings per share related to income from discontinued operations for the Path 15, Auburndale, Lake and Pasco projects was $0.01 and $0.10 for the three months ended March 31, 2013 and 2012, respectively.

(in millions)	March 31, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 5.0	$ 6.5
Restricted cash	16.5	12.6
Accounts receivable	22.6	21.9
Other current assets	5.6	6.3
	49.7	47.3
Non-current assets assets:		
Property, plant & equipment	110.1	111.9
Transmission system rights	170.5	172.4
Goodwill	8.9	8.9
Other assets	7.6	10.9
Assets held for sale	346.8	351.4
Current liabilities:		
Accounts payable and other accrued liabilities	$ 15.5	$ 16.5
Current portion of long-term debt	13.0	14.3
Current portion of derivative instruments liability	11.5	20.0
Other liabilities	27.8	0.5
	67.8	51.3
Long term liabilities		
Long-term debt	137.5	137.7
Liabilities held for sale	205.3	189.0

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. 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 as of March 31, 2013 and 2012:

(in millions)	Three months ended March 31, 2013 Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 729.7	$ 221.3	$ 235.4	$ 1,186.4
Net income (loss)	6.5	3.2	(1.9)	7.8
Realized and unrealized loss on hedging activities, net of tax	0.3			0.3
Foreign currency translation adjustment, net of tax	(12.1)			(12.1)
Common shares issued for LTIP	0.3			0.3
Contribution by noncontrolling interest			2.0	2.0
Costs associated with tax equity raise	(0.7)			(0.7)
Dividends paid to noncontrolling interest			(1.0)	(1.0)
Dividends declared on common shares	(24.6)			(24.6)
Dividends declared on preferred shares of a subsidiary company		(3.2)		(3.2)
Balance at March 31	$ 699.4	$ 221.3	$ 234.5	$ 1,155.2

	Three months ended March 31, 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)	(42.3)	3.2	(0.2)	(39.3)
Realized and unrealized loss on hedging activities, net of tax	0.2			0.2
Foreign currency translation adjustment, net of tax	17.2			17.2
Common shares issued for LTIP	0.2			0.2
Dividends declared on common shares	(32.4)			(32.4)
Dividends declared on preferred shares of a subsidiary company		(3.2)		(3.2)
Balance at March 31	$ 834.4	$ 221.3	$ 2.8	$ 1,058.5

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. 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 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 March 31, 2013						
Project revenues	$ 67.8	$	$ 24.7	$ 48.0	$ (0.3)	$ 140.2
Segment assets	1,147.1	372.6	1,192.6	1,143.8	83.3	3,939.4
Project Adjusted EBITDA	$ 45.9	$ 2.1	$ 21.3	$ 16.0	$ (4.7)	80.6
Change in fair value of derivative instruments	(8.1)	(1.3)	(3.0)		0.9	(11.5)
Depreciation and amortization	20.1	1.5	15.8	15.0		52.4
Interest, net	4.4		4.7	0.2	0.2	9.5
Other project (income) expense	0.4				(1.3)	(0.9)
Project income (loss)	29.1	1.9	3.8	0.8	(4.5)	31.1
Administration					8.3	8.3
Interest, net					25.9	25.9
Foreign exchange gain					(7.5)	(7.5)
Income (loss) from continuing operations before income taxes	29.1	1.9	3.8	0.8	(31.2)	4.4
Income tax benefit					(2.5)	(2.5)
Net income (loss) from continuing operations	29.1	1.9	3.8	0.8	(28.7)	6.9
Income from discontinued operations		0.3		0.6		0.9
Net income (loss)	$ 29.1	$ 2.2	$ 3.8	$ 1.4	$ (28.7)	$ 7.8

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three months ended March 31, 2012						
Project revenues	$ 67.2	$	$ 15.3	$ 35.5	$ 0.7	$ 118.7
Segment assets	1,198.7	431.0	825.0	940.7	80.3	3,475.7
Project Adjusted EBITDA	$ 42.4	$ 2.1	$ 13.4	$ 12.1	$ (3.4)	66.6
Change in fair value of derivative instruments	58.0	(0.5)				57.5
Depreciation and amortization	17.4	1.4	10.4	10.6	0.1	39.9
Interest, net	4.7		1.1		0.2	6.0
Other project (income) expense	0.2			0.1	(0.1)	0.2
Project (loss) income	(37.9)	1.2	1.9	1.4	(3.6)	(37.0)
Administration					7.7	7.7
Interest, net					22.0	22.0
Foreign exchange loss					1.0	1.0
Income (loss) from continuing operations before income taxes	(37.9)	1.2	1.9	1.4	(34.3)	(67.7)
Income tax benefit					(16.9)	(16.9)
Net income (loss) from continuing operations	(37.9)	1.2	1.9	1.4	(17.4)	(50.8)
Income from discontinued operations		10.6		1.0		11.6
Net income (loss)	$ (37.9)	$ 11.8	$ 1.9	$ 2.4	$ (17.4)	$ (39.2)

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 March 31,		Property, Plant and Equipment, net of accumulated depreciation	
	2013	2012	March 31, 2013	December 31, 2012
United States	$ 72.7	$ 55.4	$ 1,489.5	$ 1,504.8
Canada	67.5	63.3	530.5	550.7
Total	$ 140.2	$ 118.7	$ 2,020.0	$ 2,055.5

The Ontario Electricity Financial Corp ("OEFC") and British Columbia Hydro and Power Authority ("BC Hydro") provided for approximately 36.0% and 12.1%, respectively, of total consolidated revenues for the three months ended March 31, 2013 and approximately 40.3% and 12.9%, respectively, of total consolidated revenues for the three months ended March 31, 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.

13. 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Commitments and contingencies (Continued)

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 and April 2, 2013, two 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 and 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 May 2, 2013, a statement of claim relating to the April 2, 2013 notice of action was filed with the Ontario Superior Court of Justice in the Province of Ontario.

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.

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. 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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Commitments and contingencies (Continued)

of alleged damages in the respective U.S. and Canadian Actions other than in the 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 these litigations. 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 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 March 31, 2013.

14. 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Guarantees and condensed consolidating financial information (Continued)

contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

As of March 31, 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 March 31, 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 Auburndale, LLC, Auburndale LP, LLC, Auburndale GP, 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, NCP Gem, LLC, NCP Lake Power, LLC, Lake Investment, LP, Teton New Lake, LLC, Lake Cogen Ltd., Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, NCP Dade Power, LLC, NCP Pasco LLC, Dade Investment, LP, Pasco Cogen, Ltd., 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.

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)

14. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

March 31, 2013

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

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Assets					
Current assets:					
Cash and cash equivalents	$ 79.4	$	$ 6.3	$	$ 85.7
Restricted cash	43.5				43.5
Accounts receivable	142.5	14.5	2.1	(80.7)	78.4
Prepayments, supplies, and other current assets	43.9	1.1	6.3	(1.0)	50.3
Asset held for sale	346.8				346.8
Total current assets	656.1	15.6	14.7	(81.7)	604.7
Property, plant, and equipment, net	1,849.0	172.3		(1.3)	2,020.0
Equity investments in unconsolidated affiliates	4,692.1		1,001.3	(5,282.3)	411.1
Other intangible assets, net	350.6	155.1			505.7
Goodwill	276.5	58.2			334.7
Other assets	523.6		438.6	(899.0)	63.2
Total assets	$ 8,347.9	$ 401.2	$ 1,454.6	$ (6,264.3)	$ 3,939.4
Liabilities					
Current liabilities:					
Accounts payable and accrued liabilities	$ 87.9	$ 16.5	$ 63.7	$ (80.7)	$ 87.4
Revolving credit facility	44.1		20.0		64.1
Current portion of long-term debt	121.7				121.7
Liabilities held for sale	205.3				205.3
Other current liabilities	28.7		3.9	(1.0)	31.6
Total current liabilities	487.7	16.5	87.6	(81.7)	510.1
Long-term debt	824.1	190.0	460.0		1,474.1
Convertible debentures			418.2		418.2
Other non-current liabilities	1,217.0	8.4	0.5	(844.1)	381.8
Equity					
Common shares	5,082.0	186.3	1,285.3	(5,268.3)	1,285.3
Preferred shares issued by a subsidiary company	256.7			(35.4)	221.3
Accumulated other comprehensive loss	(2.4)				(2.4)
Retained deficit	248.3		(797.0)	(34.8)	(583.5)

Total Atlantic Power Corporation shareholders' equity	5,584.6	186.3	488.3	(5,338.5)	920.7
Noncontrolling interests	234.5				234.5
Total equity	5,819.1	186.3	488.3	(5,338.5)	1,155.2
Total liabilities and equity	$ 8,347.9	$ 401.2	$ 1,454.6	$ (6,264.3)	$ 3,939.4

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended March 31, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 131.6	$ 8.8	$	$ (0.2)	$ 140.2
Project expenses:					
Fuel	49.6				49.6
Operations and maintenance	26.5	1.6	0.3	(0.1)	28.3
Development	1.7				1.7
Depreciation and amortization	37.5	3.8			41.3
	115.3	5.4	0.3	(0.1)	120.9
Project other income (expense):					
Change in fair value of derivative instruments	12.6				12.6
Equity in earnings of unconsolidated affiliates	7.2				7.2
Interest, net	(5.2)	(2.8)			(8.0)
	14.6	(2.8)			11.8
Project income (loss)	30.9	0.6	(0.3)	(0.1)	31.1
Administrative and other expenses (income):					
Administration	4.6		3.7		8.3
Interest, net	19.3		6.6		25.9
Foreign exchange gain	(2.5)		(5.0)		(7.5)
	21.4		5.3		26.7
Income (loss) from continuing operations before income taxes	9.5	0.6	(5.6)	(0.1)	4.4
Income tax benefit	(2.5)				(2.5)
Net income (loss) from continuing operations	12.0	0.6	(5.6)	(0.1)	6.9
Net income from discontinued operations	0.9				0.9
Net income (loss)	12.9	0.6	(5.6)	(0.1)	7.8
Net income (loss) attributable to noncontrolling interest	(1.9)			3.2	1.3
Net income (loss) attributable to Atlantic Power Corporation	$ 14.8	$ 0.6	$ (5.6)	$ (3.3)	$ 6.5

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME

Three months ended March 31, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net income (loss)	$ 12.9	$ 0.6	$ (5.6)	$ (0.1)	$ 7.8
Other comprehensive income (loss):					
Net amount reclassified to earnings	0.3				0.3
Net unrealized losses on derivatives	0.3				0.3
Foreign currency translation adjustments	(12.1)				(12.1)
Other comprehensive loss, net of tax	(11.8)				(11.8)
Comprehensive income (loss)	1.1	0.6	(5.6)	(0.1)	(4.0)
Less: Comprehensive income attributable to noncontrolling interests	1.3				1.3
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ (0.2)	$ 0.6	$ (5.6)	$ (0.1)	$ (5.3)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Three months ended March 31, 2013

(in millions of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net cash provided by operating activities	$ 51.3	$ 0.2	$ 22.7	$	$ 74.2
Cash flows used in investing activities:					
Acquisitions and investments, net of cash acquired	3.0		(3.0)		
Construction in progress	(9.7)				(9.7)
Change in restricted cash	(18.7)				(18.7)
Purchase of property, plant and equipment	(2.0)	(0.2)			(2.2)
Net cash used in investing activities	(27.4)	(0.2)	(3.0)		(30.6)
Cash flows provided by financing activities:					
Offering costs related to tax equity	(0.6)				(0.6)
Repayment for long-term debt	(2.6)				(2.6)
Proceeds from project-level debt	20.8				20.8
Payments for revolving credit facility borrowings	(2.9)				(2.9)
Equity contribution from noncontrolling interest			2.0		2.0
Dividends paid	(4.0)		(32.3)		(36.3)
Net cash provided by (used in) financing activities	10.7		(30.3)		(19.6)
Net increase (decrease) in cash and cash equivalents	34.6		(10.6)		24.0
Less cash at discontinued operation	(5.0)				(5.0)
Cash and cash equivalents at beginning of period at discontinued operations	6.5				6.5
Cash and cash equivalents at beginning of period	43.3		16.9		60.2
Cash and cash equivalents at end of period	$ 79.4	$	$ 6.3	$	$ 85.7

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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; 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, thermal energy and transmission services 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;

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;
- compliance with our senior credit facility and our ability to obtain requested waivers and/or amendments;
- 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 March 31, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,965 MW in which our aggregate ownership interest is approximately 2,046 MW. As of May 6, 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 the Florida Projects and Path 15 which are designated as held for sale at March 31, 2013, our 17.1% interest in Gregory for which we entered into an agreement to sell in April 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. This includes Piedmont, our 53 MW biomass project in Georgia, which achieved commercial operations in April 2013. In December 2012, we acquired a wind

and solar development company, 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, 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.

Effective April 2, 2013, we appointed Edward Hall as Executive Vice President Chief Operating Officer of Atlantic Power.

RECENT DEVELOPMENTS

Canadian Hills Tax Equity

On May 2, 2013, we sold our tax equity ownership 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 no gain or loss on the sale. The cash proceeds will be held for general corporate purposes and to invest in future accretive growth opportunities. We continue to own 99% of the project and consolidate it in our consolidated financial statements. Income attributable to the tax investors is recorded as a component of noncontrolling interests.

Piedmont Commercial Operations

On April 19, 2013, Piedmont achieved commercial operation under its PPA with Georgia Power Company at a declared capacity of 53.5 MW. 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.

Piedmont expects to submit an application under the federal 1603 grant program within 60 days from commercial operation. The project's outstanding $51 million bridge loan is expected to be repaid largely from the proceeds of the 1603 grant with a possible contribution from the Company of approximately $2.0 million to cover the shortfall created by the U.S. federal budget sequestration. Piedmont's construction loan in the amount of $82 million ($76.6 million at March 31, 2013) is expected to be converted into a term loan. While we fully expect the construction loan to convert to a

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term loan in second quarter 2013 based on the project meeting specified milestone requirements, if it does not, we have the option of amending or refinancing the construction loan or infusing additional equity into the project.

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 $272.8 million including working capital adjustments. We expect to receive net cash proceeds from our ownership interest of approximately $33.7 million in the aggregate, after repayment of project-level debt and transaction expenses. We intend to use the net proceeds from the sale for general corporate purposes and to invest in future accretive growth opportunities. We expect the sale of Gregory to close in the third quarter of 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 held for general corporate purposes and to invest in future accretive growth opportunities. On April 30, 2013, we recorded a gain on sale of approximately $7.0 million. All project level debt issued by Path 15, totaling $137.2 million as of March 31, 2013, transferred with the sale. Path 15 is accounted for as an asset held for sale in the consolidated balance sheets at March 31, 2013 and December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the three months ended March 31, 2013 and 2012.

Sale of Florida Projects

On January 30, 2013, we entered into a purchase and sale agreement for the sale of Auburndale, Lake and Pasco, our 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.

OUR POWER PROJECTS

The table on the following page outlines our portfolio of power generating assets in operation as of May 6, 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

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each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
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.	July 2012[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		43	100.00%	43			AA-

		Natural Gas				Ontario Electricity Financial Corp	December 2014	
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(3)	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(4)	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. We are currently in negotiations with the purchaser regarding the renewal of the ESA with plans on signing a new contract in the second quarter of 2013.

(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)

Piedmont achieved commercial operations on April 19, 2013.

(4) We are currently considering various options regarding Greeley for the PPA expiry 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 months ended March 31, 2013 and 2012 which are analyzed in greater detail below:

	Three months ended March 31,	
	2013	2012
Project income (loss)	$ 31.1	$ (37.0)
Income (loss) from continuing operations	4.4	(67.7)
Income from discontinued operations, net of tax	0.9	11.6
Net income (loss) attributable to Atlantic Power Corporation	6.5	(42.3)
Basic and diluted earnings (loss) per share from continuing operations	$ 0.04	$ (0.47)
Project Adjusted EBITDA[1]	80.6	66.6
Cash Available for Distribution[1]	66.2	59.9

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

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Three months ended March 31, 2013 compared to the three months ended March 31, 2012

The following table provides our consolidated results of operations:

	Three months ended March 31,			
	2013	2012	$ change	% change
Project revenue:				
Energy sales	$ 69.0	$ 60.0	9.0	15.0%
Energy capacity revenue	44.8	37.0	7.8	21.1%
Other	26.4	21.7	4.7	21.7%
	140.2	118.7	21.5	18.1%
Project expenses:				
Fuel	49.6	46.2	3.4	7.4%
Operations and maintenance	28.3	24.7	3.6	14.6%
Development	1.7		1.7	NM
Depreciation and amortization	41.3	26.5	14.8	55.8%
	120.9	97.4	23.5	24.1%
Project other income (expense):				
Change in fair value of derivative instruments	12.6	(57.2)	69.8	NM
Equity in earnings of unconsolidated affiliates	7.2	2.9	4.3	NM
Interest, net	(8.0)	(4.0)	(4.0)	NM
	11.8	(58.3)	70.1	NM
Project income (loss)	31.1	(37.0)	68.1	NM
Administrative and other expenses (income):				
Administration	8.3	7.7	0.6	7.8%
Interest, net	25.9	22.0	3.9	17.7%
Foreign exchange (gain) loss	(7.5)	1.0	(8.5)	NM
	26.7	30.7	(4.0)	-13.0%
Income (loss) from continuing operations before income taxes	4.4	(67.7)	72.1	NM
Income tax benefit	(2.5)	(16.9)	14.4	85.2%
Income (loss) from continuing operations	6.9	(50.8)	57.7	NM
Income from discontinued operations, net of tax	0.9	11.6	(10.7)	-92.2%
Net income (loss)	7.8	(39.2)	47.0	NM
Net loss attributable to noncontrolling interests	(1.9)	(0.1)	(1.8)	NM
Net income attributable to preferred shares dividends of a subsidiary company	3.2	3.2		NM
Net income (loss) attributable to Atlantic Power Corporation	$ 6.5	$ (42.3)	48.8	115.4%

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. These costs are not allocated to the operating segments when determining segment profit or loss.

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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 March 31, 2013					
	Northeast	Southeast(1)	Northwest	Southwest(2)	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 36.0	$	$ 17.4	$ 15.7	$ (0.1)	$ 69.0
Energy capacity revenue	22.7			21.9	0.2	44.8
Other	9.1		7.3	10.4	(0.4)	26.4
	67.8		24.7	48.0	(0.3)	140.2
Project expenses:						
Fuel	25.3		3.3	21.0		49.6
Operations and maintenance	8.1		5.8	12.2	2.2	28.3
Development					1.7	1.7
Depreciation and amortization	15.2		11.7	14.4		41.3
	48.6		20.8	47.6	3.9	120.9
Project other income (expense):						
Change in fair value of derivative instruments	8.4	1.3	2.8		0.1	12.6
Equity in earnings of unconsolidated affiliates	5.5	0.6	0.7	0.6	(0.2)	7.2
Interest, net	(4.0)		(3.6)	(0.2)	(0.2)	(8.0)
	9.9	1.9	(0.1)	0.4	(0.3)	11.8
Project income (loss)	$ 29.1	$ 1.9	$ 3.8	$ 0.8	$ (4.5)	$ 31.1

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	Three months ended March 31, 2012					
	Northeast	Southeast[(1)]	Northwest	Southwest[(2)]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 38.3	$	$ 8.8	$ 12.9	$	$ 60.0
Energy capacity revenue	22.4			14.6		37.0
Other	6.5		6.5	8.0	0.7	21.7
	67.2		15.3	35.5	0.7	118.7
Project expenses:						
Fuel	26.2		3.8	16.2		46.2
Operations and maintenance	8.8		3.8	7.8	4.3	24.7
Depreciation and amortization	12.2		6.4	7.9		26.5
	47.2		14.0	31.9	4.3	97.4
Project other income (expense):						
Change in fair value of derivative instruments	(57.9)	1.4			(0.7)	(57.2)
Equity in earnings of unconsolidated affiliates	3.9	(0.2)	0.6	(2.2)	0.8	2.9
Interest, net	(3.9)				(0.1)	(4.0)
	(57.9)	1.2	0.6	(2.2)		(58.3)
Project income (loss)	$ (37.9)	$ 1.2	$ 1.9	$ 1.4	$ (3.6)	$ (37.0)

(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 three months ended March 31, 2013 increased $67.0 million from the comparable 2012 period primarily due to:

- increased project income from Kapuskasing of $30.8 million due primarily to a positive $32 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;
- increased project income from North Bay of $31.4 million due primarily to a positive $32 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives; and
- increased project income from Nipigon of $3.2 million due primarily to a positive $1.8 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives.

Southeast

Project income for the three months ended March 31, 2013 increased $0.7 million from the comparable 2012 period due to increased project income of $0.8 million at the Orlando project. This increase is primarily attributable to a positive $0.5 million non-cash change in fair value of natural gas swap derivative instruments.

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Project income for the Southeast segment excludes the Florida Projects which are accounted for as assets held for sale and as a component of discontinued operations and did not change materially for the three months ended March 31, 2013 from the comparable 2012 period.

Northwest

Project income for the three months ended March 31, 2013 increased $1.9 million from the comparable 2012 period primarily due to:

- increased project income from Williams Lake of $2.3 million due to increased generation; and
- increased project income from Rockland of $0.9 million attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition during the fourth quarter of 2012.

These increases were partially offset by:

- a project loss from Meadow Creek, which was acquired in December 2012, of $1.1. The loss was primarily due to $3.6 million of depreciation and amortization, $2.2 million of interest expense and $1.0 million of operating expense, partially offset by project revenues of $4.1 million and a $1.6 million non-cash increase in the fair value of the project's interest rate swaps accounted for as derivatives.

Southwest

Project income for the three months ended March 31, 2013 decreased $0.6 million from the comparable 2012 period primarily due to:

- decreased project income from Morris of $3.1 million due to a $3.3 million increase in maintenance costs, lower revenue and higher fuel costs.

This decrease was partially offset by:

- increased project income of $2.1 million at Gregory primarily attributable to increased generation and decreased maintenance costs resulting from an outage during the first quarter of 2012.

Project income for the Southwest segment excludes the Path 15 project which is accounted for as an asset held for sale and as a component of discontinued operations. Project income for Path 15 was $1.0 million and $1.8 million for the three months ended March 31, 2013 and 2012, respectively and did not change materially.

Un-allocated Corporate

Total project loss increased $0.9 million for the three months ended March 31, 2013 from the comparable 2012 period primarily due to higher general and administrative expenses.

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

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equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

Administration

The $0.6 million or 7.8% increase to administration expense from the comparable 2012 period was not material.

Interest, net

Interest expense increased $3.9 million or 17.7% 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) loss

Foreign exchange gain increased $8.5 million primarily due to a $14.7 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars and a $3.2 million decrease in unrealized loss on foreign exchange forward contracts, offset by a $9.4 million decrease in realized gains on the settlement of foreign currency forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.016 at March 31, 2013 and increased by 2.1% in 2013 compared to a decrease of 1.9% in the comparable 2012 period.

Income tax benefit

Income tax benefit for the three months ended March 31, 2013 was $2.5 million. The difference between the actual tax benefit of $2.5 million and the expected income tax expense of $1.1 million, based on the Canadian enacted statutory rate of 25%, is primarily due to $1.8 million related to operating projects in higher tax jurisdictions, $2.3 million in foreign exchange and $2.4 million in other permanent differences. These amounts are partially offset by $2.9 million change in the valuation allowance. For the three months ended March 31, 2012, the actual and expected income tax benefit from continuing operations was $16.9 million. Items impacting the tax rate during the period include $2.6 million relating to operating projects in higher tax rate jurisdictions and $10.9 million from a change in estimates of equity method investments and various other permanent differences, entirely offset by $2.6 million in foreign exchange and a $12.4 million change in the valuation allowance.

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Generation and Availability

	Three months ended March 31,		
	2013	2012	% change 2013 vs. 2012
Aggregate power generation (Net MWh)			
Northeast	697,776	665,193	4.9%
Southeast[(1)]	104,963	104,727	0.3%
Northwest	352,356	248,048	42.0%
Southwest[(2)]	757,339	474,630	59.6%
Total	1,912,424	1,492,598	28.1%
Weighted average availability			
Northeast	97.2%	98.6%	-1.4%
Southeast[(1)]	99.9%	100.0%	-0.1%
Northwest	91.4%	93.2%	-1.9%
Southwest[(2)]	95.0%	97.3%	-2.4%
Total	95.6%	97.4%	-1.8%

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

(2) Excludes the Delta-Person and Gregory projects for which we entered into agreements to sell.

Three months ended March 31, 2013 compared with three months ended March 31, 2012

Aggregate power generation for the three months ended March 31, 2013 increased 28.1% from the comparable 2012 period primarily due to:

- increased generation in the Northwest segment due to Meadow Creek, which achieved commercial operations in late December 2012, as well as generation from Goshen North and increased ownership of Rockland, both 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.

Weighted average availability decreased from 97.4% for the three months ended March 31, 2012 to 95.6% for the three months ended March 31, 2013 period primarily due to:

- decreased availability in the Southwest segment resulting from maintenance at Morris during the first quarter of 2013; and

- decreased availability in the Northeast segment resulting from maintenance at Curtis Palmer to replace a turbine in the first quarter of 2013 as well as decreased availability at Kapuskasing, Calstock and Tunis, all of which underwent minor maintenance during the first quarter of 2013.

Generation and availability statistics for the Southeast segment exclude the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Total generation for Auburndale was 269,394 MWh and 190,186 MWh and availability was 98.8% and 99.1% for the three months ended March 31, 2013 and 2012, respectively. Total generation for Lake was 240,427 MWh and 118,069 MWh and availability was 97.3% and 98.2% for the three months ended March 31, 2013 and 2012, respectively. Total generation for Pasco was 39,270 MWh and 46,290 MWh and availability was 91.6% and 97.6% for the three months ended March 31, 2013 and 2012, respectively.

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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 12 to the consolidated financial statements. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Project Adjusted EBITDA

	Three months ended March 31,	
	2013	**2012**
	(unaudited)	
Project Adjusted EBITDA by Segment		
Northeast	$ 45.9	$ 42.4
Southeast[(1)]	2.1	2.1
Northwest	21.3	13.4
Southwest[(2)]	16.0	12.1
Un-allocated corporate	(4.7)	(3.4)
Total	80.6	66.6
Reconciliation to project income (loss)		
Depreciation and amortization	52.4	39.9
Interest, net	9.5	6.0
Change in the fair value of derivative instruments	(11.5)	57.5
Other (income) expense	(0.9)	0.2
Project income (loss)	31.1	(37.0)

(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

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

	Three months ended March 31,		
	2013	2012	% change 2013 vs. 2012
Northeast			
Project Adjusted EBITDA	$ 45.9	$ 42.4	8%

Three months ended March 31, 2013 compared with three months ended March 31, 2012

Project Adjusted EBITDA for the three months ended March 31, 2013 increased $3.5 million or 8% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $1.6 million at Calstock primarily attributable to increased generation and higher capacity revenues resulting from escalation adjustments under its PPA; and

- $1.7 million at Nipigon primarily attributable to higher generation and capacity revenues resulting from escalation adjustments under its PPA as well as lower maintenance costs resulting from an inspection in 2012.

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

- $1.8 million at Curtis Palmer primarily attributable to lower revenues resulting from lower water flows from the comparable 2012 period and maintenance to replace a turbine during the first quarter of 2013.

Southeast

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

	Three months ended March 31,		
	2013	2012	% change 2013 vs. 2012
Southeast			
Project Adjusted EBITDA	$ 2.1	$ 2.1	NM

Three months ended March 31, 2013 compared with three months ended March 31, 2012

Project Adjusted EBITDA in the Southeast segment did not change materially.

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 $10.5 million and $10.6 million for the three months ended March 31, 2013 and 2012, respectively and did not change materially.

Project Adjusted EBITDA for Lake was $13.1 million and $8.0 million for the three months ended March 31, 2013 and 2012, respectively.

- The increase is due primarily to a combination of increased generation, higher average energy prices, and higher capacity revenues resulting from contract escalation clauses.

Project Adjusted EBITDA for Pasco was $1.1 million and $0.9 million for the three months ended March 31, 2013 and 2012, respectively and did not change materially.

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Northwest

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

	Three months ended March 31,		
	2013	2012	% change 2013 vs. 2012
Northwest			
Project Adjusted EBITDA	$ 21.3	$ 13.4	59%

Three months ended March 31, 2013 compared with three months ended March 31, 2012

Project Adjusted EBITDA for the three months ended March 31, 2013 increased by $7.9 million or 59% from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $1.7 million at Rockland attributable to an ownership percentage increase from 30% to 50% resulting from the Ridgeline acquisition during the fourth quarter of 2012;
- $3.1 million at Meadow Creek which was acquired in December 2012; and
- $2.3 million at Williams Lake attributable to higher revenues from increased generation and lower fuel costs.

Southwest

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

	Three months ended March 31,		
	2013	2012	% change 2013 vs. 2012
Southwest			
Project Adjusted EBITDA	$ 16.0	$ 12.1	32%

Three months ended March 31, 2013 compared with three months ended March 31, 2012

Project Adjusted EBITDA for the three months ended March 31, 2013 increased by $3.9 million from the comparable 2012 period primarily due to increases in Project Adjusted EBITDA of:

- $6.7 million at Canadian Hills, which became commercially operational during the fourth quarter of 2012; and
- $2.0 million at Gregory attributable to $1.3 million decrease in maintenance costs resulting from an expected outage during the first quarter of 2012.

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

- $2.9 million at Morris attributable to an increase in maintenance costs, lower revenue and higher fuel costs.

Project Adjusted EBITDA for the Southwest segment excludes the Path 15 project which is accounted for as a component of discontinued operations. Project Adjusted EBITDA for Path 15 was $6.2 million and $6.7 million for the three months ended March 31, 2013 and 2012, respectively and did not change materially.

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Cash Available for Distribution

The payout ratio associated with the cash dividends declared to shareholders was 38% and 55% for the three months ended March 31, 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 2013 was positively impacted primarily 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 three months ended March 31, 2012 was positively impacted by an increase in working capital associated with the Ontario plants acquired in the Partnership acquisition as well as reducing our combined foreign currency forward positions as a result of the acquisition of the Partnership. 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 months ended March 31, 2013 and 2012, and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

(in millions of U.S. dollars, except as otherwise stated)	Three months ended March 31, 2013	Three months ended March 31, 2012
	(unaudited)	
Cash flows from operating activities	$ 74.2	$ 66.6
Project-level debt repayments	(2.6)	(2.7)
Purchases of property, plant and equipment	(2.2)	(0.8)
Dividends on preferred shares of a subsidiary company	(3.2)	(3.2)
Cash Available for Distribution[1]	66.2	59.9
Total cash dividends declared to shareholders	25.2	32.8
Payout ratio	38%	55%

(1) 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 March 31, 2013, cash and cash equivalents increased $25.5 million from December 31, 2012 to $85.7 million. The increase in cash and cash equivalents was due to $74.2 million provided by operating activities offset by $19.6 million of cash used in financing activities and $30.6 million of cash used for investing activities. The operating, investing and financing activities include the Florida Projects and Path 15 assets held for sale. There was $5.0 million and $6.5 million of cash located at these projects at March 31, 2013 and December 31, 2012, respectively.

At March 31, 2012, cash and cash equivalents increased $46.0 million from December 31, 2011 to $106.6 million. The increase in cash and cash equivalents was primarily due to $66.6 million provided

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by operating activities and $150.1 million of cash provided by financing activities, offset by $170.7 million of cash used in investing activities.

	Three months ended March 31, 2013	2012	$ Change 2013 vs. 2012
Net cash provided by operating activities	$ 74.2	$ 66.6	$ 7.6
Net cash used in investing activities	(30.6)	(170.7)	140.1
Net cash (used in) provided by financing activities	(19.6)	150.1	(169.7)

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, changes in regulated transmission rates 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 three months ended March 31, 2013 over 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 used in investing activities includes cash used to fund acquisitions in North American markets. Cash flows used in investing activities for the three months ended March 31, 2013 were $30.6 million compared to cash flows used in investing activities of $170.7 million for the three months ended March 31, 2012. The change is due to a $153.8 million decrease 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 a $12.4 increase in the change in restricted cash.

Financing Activities

Cash provided by financing activities for the three months ended March 31, 2013 resulted in a net outflow of $19.6 million compared to a net inflow of $150.1 million for the same period in 2012. The change from the prior year is due to a $163.4 million decrease in the proceeds from long-term debt primarily attributable to $176.1 construction loan proceeds received for the Canadian Hills construction loan in the three months ended March 31, 2012.

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Liquidity and Capital Resources

(in millions of U.S. dollars, except as otherwise stated)		March 31, 2013		December 31, 2012
Cash and cash equivalents	$	85.7	$	60.2
Restricted cash		43.5		28.6
Total		129.2		88.8
Revolving credit facility availability		124.3		120.1
Total liquidity	$	253.5	$	208.9

Overview

Our primary sources of liquidity are distributions from our projects and availability under our revolving credit facility. Substantially all of the cash received from project distributions is used to pay dividends to our 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. Cash and cash equivalents and restricted cash at March 31, 2013 exclude $16.5 million related to the Florida Projects and Path 15 which are classified as assets held for sale.

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 May 6, 2013, there are no debt instruments with maturities in 2013 other than the cash grant loan at Piedmont, which will be repaid mostly by the 1603 Grant and some cash on hand. 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. The senior credit facility matures on November 4, 2015. As of March 31, 2013, $111.6 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. On April 30, 2013, letters of credit issued, but not drawn, were reduced to $82.5 million resulting from the sale of the Florida Projects and Path 15. We must meet certain financial covenants under the terms of our senior credit facility, which are generally based on ratios as described in Note 9 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2012. As of May 6, 2013, we were in compliance with these ratios. After further review of our currently forecasted results for the remainder of the year, we anticipate that, it is likely we will not meet the covenant in our senior credit facility requiring that our ratio of Consolidated EBITDA to Consolidated Interest Expense (as described in the senior credit facility) exceeds 2.25, with respect to the quarter-end testing date for one or more of the remaining quarterly periods in the balance of the 2013 fiscal year. We are currently in discussions with our lenders to obtain a waiver of compliance with this ratio for the balance of the fiscal year and/or an amendment to the senior credit facility. We anticipate receiving a waiver for this possible default or an amendment to the applicable ratio, although no assurance can be given that we will be successful in this regard. In addition to securing such waiver and/or amendment, we plan to seek a broader amendment of our senior credit facility to take into account changes in the business development plans at Atlantic Power, which would also take into account the potential for a breach of our Leverage Ratio in early 2014, as more fully described in "Item 1A. Risk Factors", and intend to initiate discussions with our lenders in this regard. In the unlikely event that we're not successful in obtaining such waiver or amendment, based on our available cash resources, we expect to have the

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ability to cash collateralize the outstanding letters of credit under the senior credit facility and terminate the senior credit facility prior to any default (which would eliminate such facility as a source of liquidity).

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.

Corporate Debt

The following table summarizes the maturities of our corporate debt at March 31, 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%	206.7						206.7
Convertible Debenture	6.5%	44.1		44.1				
Convertible Debenture	6.3%	66.4					66.4	
Convertible Debenture	5.6%	79.2					79.2	
Convertible Debenture	5.8%	130.0						130.0
Convertible Debenture	6.0%	98.4						98.4
Total Corporate Debt		$ 1,309.8	$	$ 44.1	$ 150.0	$	$ 220.6	$ 895.1

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 March 31, 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 March 31, 2013, the covenants at the Gregory and Delta-Person 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 March 31, 2013. The amounts listed below are in thousands 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%	$ 32.7	$ 2.3	$ 5.0	$ 5.8	$ 6.0	$ 6.3	$ 7.3
Piedmont[(1)]	3.8% 5.2%	127.6	55.1	4.5	4.5	3.4	2.9	57.2
Path 15[(2)]	7.9% 9.0%	137.2	9.4	8.1	8.7	9.5	8.2	93.3
Auburndale[(3)]	7.9% 9.0%	3.7	3.7					
Cadillac	6.0% 8.0%	37.2	1.8	2.0	3.9	2.5	3.0	24.0
Rockland	6.4%	86.5	1.2	1.5	1.8	1.9	2.2	77.9
Curtis Palmer[(4)]	5.9%	190.0		190.0				
Meadow Creek[(5)]	1.3 5.1%	229.3	59.5	4.9	4.6	5.3	5.3	149.7
Total Consolidated Projects		844.2	133.0	216.0	29.3	28.6	27.9	409.4
Equity Method Projects:								
Chambers	0.6% 7.2%	49.5	8.2	1.0	0.2	0.1		40.0
Delta-Person[(6)]	1.9%	7.5	1.0	1.3	1.4	1.5	1.1	1.2
Gregory[(7)]	2.3% 7.7%	10.1	1.5	2.1	2.2	2.4	1.9	
Goshen	3.0% 6.6%	24.6	0.3	0.4	0.5	0.7	0.9	21.8
Idaho Wind	5.6%	48.3	1.6	2.4	2.6	2.5	2.7	36.5
Total Equity Method Projects		140.0	12.6	7.2	6.9	7.2	6.6	99.5
Total Project-Level Debt		$ 984.2	$ 145.6	$ 223.2	$ 36.2	$ 35.8	$ 34.5	$ 508.9

(1)
As of March 31, 2013 the balance of $127.6 million on the Piedmont debt is funded by the related bridge loan of $51.0 million and $76.6 million funded by the construction loan that we expect to convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan, a portion of which we expect to repay with the proceeds of the stimulus grant expected to be received from the U.S. Treasury, and an $82.0 million construction loan. While we fully expect the construction loan to convert to a term loan in second quarter 2013 based on the project meeting specified milestone requirements, if it does not, we have the option of amending or refinancing the construction loan or infusing additional equity into the project. Piedmont achieved commercial operations on April 19, 2013 and expects to submit an application under the 1603 federal grant program within 60 days from this date to recover approximately 30% of its capital cost, subject to the potential impact of the federal sequester on spending which we estimate to be a $2.0 million shortfall. The $51.0 million bridge loan is expected to be repaid by end of third quarter of 2013 and repayment of the expected $82.0 million term loan would commence in 2013.

(2)
Path 15 is classified as an asset held for sale as of March 31, 2013. Accordingly, the outstanding debt is recorded as a component of liabilities associated with an asset held for sale on the consolidated balance sheet at March 31, 2013.

(3)
Auburndale is classified as an asset held for sale as of March 31, 2013. Accordingly, the outstanding debt is recorded as a component of liabilities associated with an asset held for sale on the consolidated balance sheet at March 31, 2013.

(4)
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.

(5)

Meadow Creek debt consists of $172.8 million drawn on a construction loan which converted to a term loan in March 2013 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 lower project cost versus budget.

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

(7) We have entered into an agreement to sell our interest in the Gregory project with plans to close the sale in the third quarter of 2013.

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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, 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. 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 allow us to predict major maintenance events and balance the funds 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 months ended March 31, 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 March 31, 2013, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 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 May 6, 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.

The Tunis project is exposed to changes in natural gas prices under spot purchases through the expiration of its PPA in 2014. The projected annual cash distributions at Tunis in 2013 would change by approximately $1.9 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.

On April 30, 2013, we entered into a contract 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 this transaction, 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.

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. Our current exposure in 2013 to these future agreements or spot market pricing is at the Greeley project. This exposure is not material.

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 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 112% 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 March 31, 2013, the forward contracts consist of (1) monthly purchases through the end of 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$99.7 million at an average exchange rate of Cdn$1.14 per U.S. dollar. It is our intention to periodically consider extending or terminating the length of 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. Subsequent to the termination, cash flows from our projects that generate Canadian dollars and our remaining forward contracts to purchase Canadian dollars at a fixed rate, hedge an average of approximately 75% of our expected dividend, Canadian dollar denominated long-term debt and convertible debenture interest payments through 2015.

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.

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The following table contains the components of recorded foreign exchange (gain) loss for the three months ended March 31, 2013 and 2012:

	Three months ended March 31, 2013	Three months ended March 31, 2012
Unrealized foreign exchange (gain) loss:		
Convertible debentures and other	$ (11.0)	$ 3.7
Forward contracts	6.0	9.2
	(5.0)	12.9
Realized foreign exchange gains on forward contract settlements	(2.5)	(11.9)
Total foreign exchange (gain) loss	$ (7.5)	$ 1.0

The U.S dollar to Canadian dollar exchange rate was 1.016 at March 31, 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 March 31, 2013:

Convertible debentures denominated in Canadian dollars, at carrying value	$ (26.2)
Foreign currency forward contracts	$ 14.0

Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 90% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $2.5 million.

Cadillac

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

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

Piedmont

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the statements of operations. The interest rate swaps expire on February 29, 2016 and November 30, 2030, respectively.

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Epsilon Power Partners

Epsilon Power Partners, a wholly owned subsidiary, 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 a maturity date of July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' 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.

Meadow Creek

Meadow Creek executed interest rate swaps that we assumed in our acquisition to economically fix the exposure to changes in interest rates related to 62% of the outstanding variable-rate non-recourse debt. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the notional amount due of the term loan commencing on December 30, 2012 and ending December 31, 2024 and fixes the interest rate at 5.1%. 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 6.7%.

Rockland

The Rockland project entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the 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%. 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 5.1%.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the three months ended March 31, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

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

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

Shareholder class action lawsuits

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 and April 2, 2013, two 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 and 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 May 2, 2013, a statement of claim relating to the April 2, 2013 notice of action was filed with the Ontario Superior Court of Justice in the Province of Ontario.

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.

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. 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 other than in the Canadian Actions filed on March 19, 2013 and April 2, 2013 (including the related statement of claim filed on May 2,

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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 these litigations. 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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. With respect to such other matters arising in the normal course of business, there are no matters pending as of March 31, 2013 that are expected to have a material impact on our financial position or results of operations or have been reserved for as of March 31, 2013.

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.

ITEM 1A. RISK FACTORS

Other than as described below, there were no material changes to the risk factors disclosed in "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2012 (except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10-Q relates to such risk factors (including, without limitation, the matters discussed in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations").

The fifth paragraph in the risk factor ***"Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make cash distributions, acquisitions or investments or issue additional indebtedness we otherwise would seek to do"*** in our Annual Report on Form 10-K for the year ended December 31, 2012 has been updated as follows:

Our senior credit facility contains financial covenants, covenants requiring us to take certain actions and negative covenants restricting our ability to take certain actions. As of May 6, 2013, we were in compliance with all covenant ratios. After further review of our currently forecasted results for the remainder of the year, we anticipate that, it is likely we will not meet the covenant in our senior credit facility requiring that our ratio of Consolidated EBITDA (as defined in the senior credit facility) to Consolidated Interest Expense (as defined in the senior credit facility) exceeds 2.25, with respect to the quarter-end testing date for one or more of the remaining quarterly periods in the balance of the 2013 fiscal year, and we may not meet the covenant in our senior credit facility requiring that our ratio of Consolidated Total Net Debt (as defined in the senior credit facility) to Consolidated EBITDA (as defined in the senior credit facility) remains below 7.50 to 1.00 or 7.25 to 1.00 (the "Leverage Ratio"), as applicable, with respect to the quarter-end testing dates in 2014. If we are unable to meet these ratio

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covenants or other adverse events occur which may result in a breach of the ratios contained in our senior credit facility, a default under the senior credit facility would result or we may be prevented from taking certain actions that are not permitted under the senior credit facility unless certain ratios are met, including making distributions, making certain acquisitions, investments or capital expenditures, and refinancing or issuing debt, that we otherwise would seek to do. In such case, we may be required to seek waivers or consents from our lenders or amendments to our senior credit facility, or may be required to seek to refinance our senior credit facility. We are currently in discussions with our lenders to obtain a waiver of compliance with the Consolidated EBITDA to Consolidated Interest Expense ratio for the balance of the fiscal year and/or an amendment to the senior credit facility. We can provide no assurances that we will be able to obtain the waiver on terms acceptable to us or at all, and we will otherwise be in default under our senior credit facility, which would enable lenders thereunder to accelerate the repayment of amounts outstanding and exercise remedies with respect to collateral. Our ability to amend our senior credit facility or otherwise obtain waivers from our lenders depends on matters that are outside of our control and there can be no assurance that we will be successful in that regard. In addition to securing such waiver and/or amendment, we plan to seek a broader amendment of our senior credit facility to take into account changes in the business development plans at Atlantic Power, which would also take into account the anticipated breach of our Leverage Ratio in early 2014 as described above, and intend to initiate discussions with our lenders in this regard. In the event we are not able to refinance our senior credit facility or obtain waivers or amendments, our business may be materially adversely affected, including with respect to our ability to take the actions described above. In the event that we are not successful in obtaining such waiver or amendment, based on our available cash resources, we expect to have the ability to cash collateralize the outstanding letters of credit under the senior credit facility and terminate the senior credit facility prior to any default (which would eliminate such facility as a source of liquidity).

We are subject to significant pending civil litigation, which if decided against us, could require us to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity.

In addition to being subject to litigation in the ordinary course of business, we are party to numerous legal proceedings, including securities class actions, from time to time. On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints related to, among other things, claims that we made materially false and misleading statements and omissions regarding the sustainability of our common share dividend that artificially inflated the price of our common shares were filed in the United States District Court for the District of Massachusetts against us and certain of our current and former executive officers. On March 19, 2013 and April 2, 2013, two notices of action relating to purported Canadian securities class action claims were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, in the Ontario Superior Court of Justice in the Province of Ontario and on April 8, 2013, a similar claim, issued by alleged investors in Atlantic Power common shares, seeking to initiate a purported class action was filed in the Superior Court of Quebec in the Province of Quebec against us and certain of our current and former executive officers. On May 2, 2013, a statement of claim relating to the April 2, 2013 notice of action was filed with the Ontario Superior Court of Justice in the Province of Ontario. The allegations of these purported class actions are essentially the same as those asserted in the United States.

These litigations may be time consuming, expensive and distracting from the conduct of our daily business. Due to the nature of these proceedings, the lack of precise damage claims (other than in certain Canadian Actions, as defined in "Item 1. Legal Proceedings") 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 described in "Item 1. Legal Proceedings", seek damages from the defendants of material or indeterminate amounts. As a result, we

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are also unable to reasonably estimate the possible loss or range of losses, if any, arising from these litigations. Although we are unable at this time to estimate what our ultimate liability in these matters may be, it is possible that we will be required to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity. We intend to defend vigorously against these actions. For additional information with respect to these unresolved matters, see "Item 1. Legal Proceedings".

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
4.1	Sixth Supplemental Indenture, dated as of March 22, 2013, between the Company and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on March 26, 2013)
4.2	Advance Notice Policy, dated April 1, 2013 (incorporated by reference to our Current Report on Form 8-K filed on April 3, 2013)
4.3	Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between the Company and Computershare Investor Services Inc., as Rights Agent, which includes the Form of Right Certificate as Exhibit A (incorporated by reference to our Current Report on Form 8-K filed on March 1, 2013)
10.1*	Purchase and sale agreement, dated as of January 30, 2013 among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC, and Quantum Auburndale GP, LLC (as "Buyers") and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dade Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as "Sellers")
10.2	Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier 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, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013)
10.3	Consent and Release, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., the Subsidiaries signatory thereto, the Lenders signatory thereto and Bank of Montreal, as Administrative Agent and Collateral Agent (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013)
12.1*	Statement re: Computation of Ratios
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934

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Exhibit No.	Description
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Label Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

** Furnished herewith.

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SIGNATURES

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

Date: May 8, 2013	Atlantic Power Corporation		
	By:	/s/ TERRENCE RONAN	
		Name:	Terrence Ronan
		Title:	*Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*