ATLANTIC POWER CORP
Form 10-Q
May 07, 2012

Table of Contents

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, 2012

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.)
200 Clarendon Street, Floor 25 **Boston, MA** (Address of principal executive offices)	**02116** (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 2, 2012 was 113,680,643.

Table of Contents

ATLANTIC POWER CORPORATION

FORM 10-Q

THREE MONTHS ENDED MARCH 31, 2012

Index

Table of Contents

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.

Table of Contents

PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands of U.S. dollars)

	March 31, 2012 (unaudited)	December 31, 2011
Assets		
Current Assets:		
Cash and cash equivalents	$ 106,609	$ 60,651
Restricted cash	27,761	21,412
Accounts receivable	59,501	79,008
Current portion of derivative instruments asset (Notes 6 and 7)	10,610	10,411
Inventory	18,214	18,628
Prepayments and other	23,647	7,615
Refundable income taxes	2,301	3,042
Total current assets	248,643	200,767
Property, plant, and equipment, net	1,549,626	1,388,254
Transmission system rights	178,319	180,282
Equity investments in unconsolidated affiliates (Note 3)	477,098	474,351
Other intangible assets, net	597,633	584,274
Goodwill	343,586	343,586
Derivative instruments asset (Notes 6 and 7)	16,589	22,003
Other assets	64,216	54,910
Total assets	$ 3,475,710	$ 3,248,427
Liabilities		
Current Liabilities:		
Accounts payable	$ 20,561	$ 18,122
Accrued interest	33,534	19,916
Other Accrued liabilities	41,456	43,968
Revolving credit facility (Note 5)	72,800	58,000
Current portion of long-term debt (Note 5)	246,520	20,958
Current portion of derivative instruments liability (Notes 6 and 7)	50,030	20,592
Dividends payable	10,921	10,733
Other current liabilities	1,278	165
Total current liabilities	477,100	192,454
Long-term debt (Note 5)	1,364,685	1,404,900
Convertible debentures	193,269	189,563
Derivative instruments liability (Notes 6 and 7)	109,873	33,170
Deferred income taxes	165,413	182,925
Power purchase and fuel supply agreement liabilities, net	46,811	71,775
Other non-current liabilities	60,022	57,859

Commitments and contingencies (Note 12)

Total liabilities		2,417,173		2,132,646
Equity				
Common shares, no par value, unlimited authorized shares; 113,680,643 and 113,526,182 issued and outstanding at March 31, 2012 and December 31, 2011, respectively		1,217,893		1,217,265
Preferred shares issued by a subsidiary company		221,304		221,304
Accumulated other comprehensive income (loss)		12,216		(5,193)
Retained deficit		(395,743)		(320,622)
Total Atlantic Power Corporation shareholders' equity		1,055,670		1,112,754
Noncontrolling interest		2,867		3,027
Total equity		1,058,537		1,115,781
Total liabilities and equity	$	3,475,710	$	3,248,427

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(Unaudited)

	Three months ended March 31, 2012	Three months ended March 31, 2011
Project revenue:		
Energy sales	$ 75,968	$ 18,502
Energy capacity revenue	62,518	27,138
Transmission services	7,161	7,644
Other	21,963	381
	167,610	53,665
Project expenses:		
Fuel	62,099	17,068
Operations and maintenance	31,500	11,072
Depreciation and amortization	36,468	10,879
	130,067	39,019
Project other income (expense):		
Change in fair value of derivative instruments (Notes 6 and 7)	(58,122)	3,561
Equity in earnings of unconsolidated affiliates (Note 3)	2,947	1,311
Interest expense	(7,033)	(4,647)
Other income (expense), net	15	(2)
	(62,193)	223
Project (loss) income	(24,650)	14,869
Administrative and other expenses (income):		
Administration	7,833	4,054
Interest, net	22,036	3,968
Foreign exchange loss (gain) (Note 7)	986	(658)
	30,855	7,364
Income (loss) from operations before income taxes	(55,505)	7,505
Income tax expense (benefit)	(16,291)	1,523
Net (loss) income	(39,214)	5,982
Net loss attributable to noncontrolling interest	(161)	(154)
Net income attributable to Preferred share dividends of a subsidiary company	3,239	
Net (loss) income attributable to Atlantic Power Corporation	$ (42,292)	$ 6,136
Net (loss) income per share attributable to Atlantic Power Corporation shareholders: (Note 10)		
Basic	$ (0.37)	$ 0.09
Diluted	$ (0.37)	$ 0.09
Weighted average number of common shares outstanding: (Note 10)		
Basic	113,578	67,654
Diluted	113,578	68,171

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands of U.S. dollars)

(Unaudited)

	Atlantic Power Corportation Three months ended March 31,		Noncontrolling Interests Three months ended March 31,		Total Three months ended March 31,	
	2012	**2011**	**2012**	**2011**	**2012**	**2011**
Net (loss) income	$ (39,214)	$ 5,982	$ 3,078	$ (154)	$ (42,292)	$ 6,136
Other comprehensive income, net of tax:						
Unrealized loss on hedging activities	15	721			15	721
Net amount reclassified to earnings	230	(449)			230	(449)
Net unrealized losses on derivatives	245	272			245	272
Foreign currency translation adjustments	17,164				17,164	
Total other comprehensive income, net of tax	17,409	272			17,409	272
Comprehensive income (loss)	$ (21,805)	$ 6,254	$ 3,078	$ (154)	$ (24,883)	$ 6,408

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of U.S. dollars)

(Unaudited)

	Three months ended March 31, 2012	Three months ended March 31, 2011
Cash flows from operating activities:		
Net (loss) income	$ (39,214)	$ 5,982
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	36,468	10,879
Long-term incentive plan expense	1,081	825
Earnings from unconsolidated affiliates	(2,947)	(1,311)
Distributions from unconsolidated affiliates	249	1,450
Unrealized foreign exchange loss	12,916	1,878
Change in fair value of derivative instruments	58,122	(3,561)
Change in deferred income taxes	(17,676)	2,011
Accounts receivable	19,507	(419)
Prepayments, refundable income taxes and other assets	(14,134)	176
Accounts payable and accrued liabilities	10,574	1,937
Other liabilities	1,546	500
Net cash provided by operating activities	66,492	20,347
Cash flows used in investing activities:		
Proceeds from loan with Idaho Wind		5,110
Change in restricted cash	(6,349)	(7,524)
Biomass development costs	(123)	(308)
Construction in progress	(163,427)	(15,055)
Purchase of property, plant and equipment and intangibles	(716)	(338)
Net cash used in investing activities	(170,615)	(18,115)
Cash flows (used in) provided by financing activities:		
Proceeds from issuance of project-level debt	184,216	2,781
Repayment of project-level debt	(2,725)	(3,400)
Proceeds from revolving credit facility borrowings	22,800	
Repayments of revolving credit facility borrowings	(8,000)	
Dividends paid	(36,031)	(18,852)
Deferred financing costs	(10,179)	
Net cash provided by (used in) financing activities	150,081	(19,471)
Net (decrease) increase in cash and cash equivalents	45,958	(17,239)
Cash and cash equivalents at beginning of period	60,651	45,497
Cash and cash equivalents at end of period	$ 106,609	$ 28,258
Supplemental cash flow information		
Interest paid	$ 17,953	$ 4,659
Income taxes paid, net	$ 644	$ 14
Accruals for capital expenditures	$ 3,695	$

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of presentation and summary of significant accounting policies

Overview

Atlantic Power is a power generation and infrastructure company with a portfolio of assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 MW in which our ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada and an 84 mile 500-kilovolt electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer in North Carolina.

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 200 Clarendon Street, Floor 25, Boston, Massachusetts, 02116, USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. 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.

The interim consolidated financial statements 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, 2011. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of March 31, 2012, the results of operations for the three month periods ended March 31, 2012 and 2011, and our cash flows for the three month periods ended March 31, 2012 and 2011.

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

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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. 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

On January 1, 2012, we adopted changes issued by the Financial Accounting Standards Board ("FASB") to conform existing guidance regarding fair value measurement and disclosure between 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 our 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 our consolidated financial statements.

2. Acquisitions and divestitures

2012 Acquisition

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 POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestitures (Continued)

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 298.45 MW wind energy project under construction in the state of Oklahoma. On March 30, 2012, we completed the purchase of an additional 48% interest in the 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 on a $310 million non-recourse, project-level construction financing facility for the project, which includes a $290 million construction loan and a $20 million 5-year letter of credit facility. The construction loan is structured to be repaid by a tax equity investment, in which we are actively pursuing, when Canadian Hills commences commercial operations. We are committed to investing approximately $180 million of equity (net of financing costs) following the funding of the construction financing. The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at March 31, 2012.

Purchase Accounting Adjustment

In the three months ended March 31, 2012, we recorded an adjustment to intangible assets for PPAs and fuel supply agreement liabilities that resulted from our acquisition of Atlantic Power Limited Partnership, formerly Capital Power Income L.P. (the "Partnership") on November 5, 2011. The fair values of these assets acquired and liabilities assumed were refined based upon further analysis as the purchase price allocation at December 31, 2011 was preliminary. Fair values were determined by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a Level 3 fair value measurement. As a result of the adjustment, intangible assets increased by $26.0 million and fuel supply agreement liabilities increased by $26.0 million in the three months ended March 31, 2012.

2012 Divestiture

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 million, plus a management agreement termination fee of approximately $6.1 million, for a total sale price of $30.1 million. The agreed upon price for our private interest in PERH was established as of December 19, 2011 and represented a 16% discount to the 60-day volume weighted average trading price of PERH's common shares at that time. The transaction remains subject to pricing adjustment or termination under certain circumstances. Completion of the transaction is subject to PERC obtaining financing and is expected to close during the second quarter of 2012.

2011 Divestiture

On February 28, 2011, we entered into a purchase and sale agreement with a third party for the purchase of our lessor interest in the Topsham project. The transaction closed on May 6, 2011 and we received proceeds of $8.5 million. No gain or loss was recorded on the sale.

Table of Contents

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, 2012 and 2011, respectively, for our equity earnings interest in our equity method investments:

	Three months ended March 31, 2012	Three months ended March 31, 2011
Revenue		
Chambers	$ 13,227	$ 13,269
Badger Creek	1,179	3,316
Gregory	4,315	7,181
Orlando	10,812	9,926
Selkirk	12,062	10,902
Other	11,733	1,821
	53,328	46,415
Project expenses		
Chambers	9,753	9,380
Badger Creek	1,137	2,983
Gregory	5,780	6,630
Orlando	10,093	9,463
Selkirk	10,335	12,659
Other	8,394	1,428
	45,492	42,543
Project other income (expense)		
Chambers	(1,193)	(427)
Badger Creek	(4)	
Gregory	(83)	(38)
Orlando	(14)	(30)
Selkirk	(65)	(1,636)
Other	(3,530)	(430)
	(4,889)	(2,561)
Project income (loss)		
Chambers	2,281	3,462
Badger Creek	38	333
Gregory	(1,548)	513
Orlando	705	433
Selkirk	1,662	(3,393)
Other	(191)	(37)
	2,947	1,311

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Accumulated depreciation and amortization

The following table presents accumulated depreciation of property, plant and equipment and the accumulated amortization of transmission system rights and other intangible assets as of March 31, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
Property, plant and equipment	$ 132,208	$ 116,287
Transmission system rights	53,350	51,387
Other intangible assets and power purchase and fuel liabilities	110,752	88,808

5. Long-term debt

Long-term debt consists of the following:

	March 31, 2012	December 31, 2011	Interest Rate
Recourse Debt:			
Senior notes, due 2018	$ 460,000	$ 460,000	9.00%
Senior unsecured notes, due June 2036 (Cdn$210,000)	210,526	206,490	5.95%
Senior unsecured notes, due July 2014	190,000	190,000	5.90%
Senior unsecured notes, due August 2017	150,000	150,000	5.87%
Senior unsecured notes, due August 2019	75,000	75,000	5.97%
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	34,608	34,982	7.40%
Path 15 senior secured bonds	145,880	145,879	7.90% 9.00%
Auburndale term loan, due 2013	10,150	11,900	5.10%
Cadillac term loan, due 2025	39,631	40,231	6.02% 8.00%
Piedmont construction loan, due 2013	108,863	100,796	Libor plus 3.50%
Canadian Hills construction loan, due 2013	176,149		Libor plus 3.00%
Purchase accounting fair value adjustments	10,398	10,580	
Less current maturities	(246,520)	(20,958)	
Total long-term debt	$ 1,364,685	$ 1,404,900	

Notes of Atlantic Power (US) GP

Atlantic Power (US) GP, an indirect, wholly owned subsidiary acquired in connection with the acquisition of the Partnership, has outstanding $150.0 million aggregate principal amount of 5.87% senior guaranteed notes, Series A, due August 2017 (the "Series A Notes"). Interest on the Series A Notes is payable semi-annually at 5.87%. Atlantic Power (US) GP also has outstanding $75.0 million aggregate principal amount of 5.97% senior guaranteed notes, Series B, due August 2019 (the "Series B Notes"). Interest on the Series B Notes is payable semi-annually at 5.97%. The Series A Notes and Series B Notes are guaranteed by the Partnership and by Curtis Palmer LLC, a wholly-owned subsidiary of the Partnership.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Long-term debt (Continued)

Non-Recourse Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met. At March 31, 2012, all of our projects were in compliance with the covenants contained in project-level debt. However, our Epsilon Power Partners, Selkirk, Delta-Person and Gregory projects 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.

Senior Credit Facility

As of March 31, 2012, $72.8 million was drawn on the senior credit facility and $139.1 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects and the applicable margin was 2.75%.

6. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of March 31, 2012 and December 31, 2011. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	March 31, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 106,609	$	$	$ 106,609
Restricted cash	27,761			27,761
Derivative instruments asset		27,199		27,199
Total	$ 134,370	$ 27,199	$	$ 161,569
Liabilities:				
Derivative instruments liability	$	$ 159,903	$	$ 159,903
Total	$	$ 159,903	$	$ 159,903

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Fair value of financial instruments (Continued)

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 60,651	$	$	$ 60,651
Restricted cash	21,412			21,412
Derivative instruments asset		32,414		32,414
Total	$ 82,063	$ 32,414	$	$ 114,477
Liabilities:				
Derivative instruments liability	$	$ 53,762	$	$ 53,762
Total	$	$ 53,762	$	$ 53,762

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, 2012, the credit valuation adjustments resulted in a $27.1 million net increase in fair value, which consists of a $0.6 million pre-tax gain in other comprehensive income and a $26.6 million gain in change in fair value of derivative instruments, offset by a $.01 million loss in foreign exchange. As of December 31, 2011, the credit valuation adjustments resulted in a $5.8 million net increase in fair value, which consists of a $0.9 million pre-tax gain in other comprehensive income and a $5.1 million gain in change in fair value of derivative instruments, offset by a $0.2 million loss in foreign exchange.

7. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. For certain contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to 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.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Gas purchase agreements

On March 12, 2012, we discontinued the application of the normal purchase normal sales ("NPNS") exemption on gas purchase agreements at our North Bay, Kapuskasing and Nipigon projects. On that date, we entered into an agreement with a third party that resulted in the gas purchase agreements net settling. The agreements at North Bay and Kapuskasing expire on December 31, 2016 and the agreements at Nipigon expire on December 31, 2012. These gas purchase agreements are derivative financial instruments and are recorded in the consolidated balance sheet at fair value at March 31, 2012 and the changes in their fair market value from the date NPNS was discontinued through March 31, 2012 are recorded in the consolidated statement of operations.

Natural gas swaps

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. In the third quarter of 2010 we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. Also in the third quarter of 2011, we 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.

The Lake project's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement that provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel supply agreement in mid-2012 until the termination of its PPA at the end of 2013. Our strategy to mitigate the future exposure to changes in natural gas prices at Orlando, Lake and Auburndale 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 sheet at fair value and the changes in their fair market value are recorded in the consolidated statement of operations.

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% 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 changes in the fair market value is recorded in accumulated other comprehensive income.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

The Auburndale project hedged a portion of 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 5.10%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. This swap agreement is effective through November 30, 2013. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt agreement and changes in the fair market value is recorded in accumulated other comprehensive income.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% from March 31, 2011 to February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% 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 in the fourth quarter 2010 and expire on February 29, 2016 and November 30, 2030. 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.

In July 2007, we executed an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt at our wholly owned subsidiary Epsilon Power Partners. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.29%. In June 2010, the swap agreement was amended to reduce the fixed interest rate 4.24% and extend the maturity date from July 2012 to 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.

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 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 long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 85% of our expected dividend 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, 2012, 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$123.0 million at an average exchange rate of Cdn$1.127 per U.S. dollar. It is our intention to periodically consider extending the length or terminating these forward contracts.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Accounting for 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 normal purchases and normal sales exception as of March 31, 2012 and December 31, 2011:

	Units	March 31, 2012	December 31, 2011
Natural gas swaps	Natural gas (Mmbtu)	12,870	14,140
Gas purchase agreements	Natural gas (GJ)	31,785	33,957
Interest rate swaps	Interest (US$)	$ 51,376	$ 52,711
Currency forwards	Cdn$	$ 248,986	$ 312,533

Fair value of derivative instruments

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

	March 31, 2012	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,747
Interest rate swaps long-term		4,627
Total derivative instruments designated as cash flow hedges		6,374
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,755
Interest rate swaps long-term		7,919
Foreign currency forward contracts current	10,610	
Foreign currency forward contracts long-term	16,589	
Natural gas swaps current		16,706
Natural gas swaps long-term		19,838
Gas purchase agreements current		28,960
Gas purchase agreements long-term		77,351
Total derivative instruments not designated as cash flow hedges	27,199	153,529
Total derivative instruments	$ 27,199	$ 159,903

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	December 31, 2011 Derivative Assets	December 31, 2011 Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,561
Interest rate swaps long-term		5,317
Total derivative instruments designated as cash flow hedges		6,878
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,587
Interest rate swaps long-term		9,637
Foreign currency forward contracts current	10,630	224
Foreign currency forward contracts long-term	22,224	221
Natural gas swaps current		16,439
Natural gas swaps long-term		18,216
Total derivative instruments not designated as cash flow hedges	32,854	47,324
Total derivative instruments	$ 32,854	$ 54,202

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 month period ended March 31, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2011	$ (1,704)	$ 321	$ (1,383)
Change in fair value of cash flow hedges	15		15
Realized from OCI during the period	287	(57)	230
Accumulated OCI balance at March 31, 2012	$ (1,402)	$ 264	$ (1,138)

For the three month period ended March 31, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2010	$ (427)	$ 682	$ 255
Change in fair value of cash flow hedges	721		721
Realized from OCI during the period	(360)	(89)	(449)
Accumulated OCI balance at March 31, 2011	$ (66)	$ 593	$ 527

A $5.1 million loss was deferred in other comprehensive loss for natural gas swap contracts accounted for as cash flow hedges prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the remaining loss (income) in other comprehensive income of $0.1 million was recorded in change in fair value of derivative instruments for the three month periods ended March 31, 2012 and 2011, respectively.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Accounting for 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, 2012	Three months ended March 31, 2011
Natural gas swaps	Fuel	$ 4,815	$ 2,476
Gas purchase agreements	Fuel	10,829	
Foreign currency forwards	Foreign exchange (gain) loss	(11,930)	(2,537)
Interest rate swaps	Interest, net	1,157	976

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, 2012	Three months ended March 31, 2011
Natural gas swaps	Change in fair value of derivatives	$ 1,795	$ 2,883
Gas purchase agreements	Change in fair value of derivatives	57,877	
Interest rate swaps	Change in fair value of derivatives	(1,550)	678
		$ 58,122	$ 4,239
Foreign currency forwards	Foreign exchange (gain) loss	$ 5,210	$ (3,436)

8. Income taxes

The difference between the actual tax benefit of $16.3 million for the three months ended March 31, 2012 and the expected income tax benefit, based on a the Canadian enacted statutory rate of 25%, of $13.9 million is primarily due to taxable losses in higher state and local tax jurisdictions.

	Three months ended March 31, 2012	Three months ended March 31, 2011
Current income tax expense (benefit)	$ 1,385	$ (488)
Deferred tax expense (benefit)	(17,676)	2,011
Total income tax expense (benefit)	$ (16,291)	$ 1,523

As of March 31, 2012, we have recorded a valuation allowance of $97.4 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 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.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Long-term incentive plan

The following table summarizes the changes in LTIP notional units during the three months ended March 31, 2012:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2011	485,781	$ 11.49
Granted	209,009	$ 14.65
Additional shares from dividends	8,172	$ 12.02
Vested	(231,687)	$ 10.10
Outstanding at March 31, 2012	471,275	$ 13.81

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 2012 is recorded net of estimated forfeitures. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

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, 2012 and December 31, 2011:

	March 31, 2012	December 31, 2011
Weighted average risk free rate of return	0.19 0.51%	0.15 0.28%
Dividend yield	8.30%	7.90%
Expected volatility Company	22.2%	22.2%
Expected volatility peer companies	17.1 112.8%	17.3 112.9%
Weighted average remaining measurement period	1.92 years	0.87 years

10. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2012. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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, 2012 and 2011:

	2012	2011
Numerator:		
Net income (loss) attributable to Atlantic Power Corporation	$ (42,292)	$ 6,136
Denominator:		
Weighted average basic shares outstanding	113,578	67,654
Dilutive potential shares:		
Convertible debentures	13,252	14,809
LTIP notional units	478	517
Potentially dilutive shares	127,308	82,980
Diluted EPS	$ (0.37)	$ 0.09

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the three months ended March 31, 2012 because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures have been excluded from fully diluted shares in the three-month period ended March 31, 2011 because their impact would be anti-dilutive.

11. Segment and geographic information

We revised our reportable business segments during the fourth quarter of 2011 subsequent to our acquisition of the Partnership. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Financial results for the three months ended March 31, 2012 and 2011 have been presented to reflect the change in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes 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. 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

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is included in the tables below.

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended March 31, 2012:						
Operating revenues	$ 66,926	$ 41,751	$ 15,300	$ 42,696	$ 937	$ 167,610
Segment assets	1,198,652	431,046	825,138	940,675	80,199	3,475,710
Project Adjusted EBITDA	$ 42,398	$ 21,674	$ 13,439	$ 18,764	$ (3,424)	$ 92,851
Change in fair value of derivative instruments	58,016	406				58,422
Depreciation and amortization	17,447	9,372	10,426	12,657	43	49,945
Interest, net	4,738	169	1,096	2,808	57	8,868
Other project (income) expense	242	14	7	82	(79)	266
Project (loss) income	(38,045)	11,713	1,910	3,217	(3,445)	(24,650)
Administration					7,833	7,833
Interest, net					22,036	22,036
Foreign exchange loss					986	986
Loss from operations before income taxes	(38,045)	11,713	1,910	3,217	(34,300)	(55,505)
Income tax expense (benefit)					(16,291)	(16,291)
Net income (loss)	$ (38,045)	$ 11,713	$ 1,910	$ 3,217	$ (18,009)	$ (39,214)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended March 31, 2011:						
Operating revenues	$ 4,547	$ 41,426	$	$ 7,644	$ 48	$ 53,665
Segment assets	288,774	360,763	47,156	226,542	84,566	1,007,801
Project Adjusted EBITDA	$ 7,488	$ 19,588	$ 866	$ 8,501	$ (450)	$ 35,993
Change in fair value of derivative instruments	490	(3,274)				(2,784)
Depreciation and amortization	4,596	9,434	439	2,961	7	17,437
Interest, net	2,434	309	370	3,089	38	6,240
Other project (income) expense	200	31				231
Project income	(232)	13,088	57	2,451	(495)	14,869
Administration					4,054	4,054
Interest, net					3,968	3,968
Foreign exchange loss					(658)	(658)
Income from operations before income taxes	(232)	13,088	57	2,451	(7,859)	7,505

Income tax expense					1,523	1,523
Net income (loss)	$ (232)	$ 13,088	$ 57	$ 2,451	$ (9,382)	$ 5,982

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

The table below provides information, by country, about our consolidated operations for the three months ended March 31, 2012 and 2011. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue		Property, Plant and Equipment, net	
	2012	2011	2012	2011
United States	$ 104,325	$ 53,665	$ 972,213	$ 284,018
Canada	63,285		577,413	
Total	$ 167,610	$ 53,665	$ 1,549,626	$ 284,018

Progress Energy Florida ("PEF") and the Ontario Electricity Financial Corp ("OEFC") provided 40.1% and 28.5%, respectively, of total consolidated revenues for the three months ended March 31, 2012. PEF and the California Independent System Operator ("CAISO") provided 71.7% and 14.2%, respectively, of total consolidated revenues for the three months ended March 31, 2011. PEF purchases electricity from the Auburndale and Lake projects in the Southeast segment, OEFC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the Northeast segment and the CAISO makes payments to Path 15 in the Southwest segment.

12. Commitments and contingencies

IRS Examination

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

We intend to vigorously contest these proposed adjustments, including pursuing all administrative and judicial remedies available to us. The Company expects to be successful in sustaining its positions with no material impact to our financial results. No accrual has been made for any contingency related to any of the proposed adjustments as of March 31, 2012.

Path 15

In February 2011, we filed a rate application with the Federal Energy Regulatory Commission ("FERC") to establish Path 15's revenue requirement at $30.3 million for the 2011-2013 period. On March 7, 2012, Path 15 filed a formal settlement agreement establishing a revenue requirement at $28.8 million with the Administrative Law Judge for her review and certification to FERC for approval. All of the parties in the rate case either support or do not oppose the settlement agreement. Path 15 expects an order approving the settlement from FERC during the second quarter of 2012.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Commitments and contingencies (Continued)

Lake

Our Lake project is currently involved in a dispute with PEF over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by PEF. The Lake project has filed a claim against PEF in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. PEF filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

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. We believe the interruption constitutes a force majeure under the energy services agreement with Equistar. Equistar disputes this interpretation and has initiated arbitration proceedings under the agreement for recovery of resulting lost profits and equipment damage among other items. The agreement with Equistar specifically shields Morris from exposure to consequential damages incurred by Equistar and management expects our insurance to cover any material losses we might incur in connection with such proceedings, including settlement costs. Management will attempt to resolve the arbitration through settlement discussions, but is prepared to vigorously defend the arbitration on the merits.

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. There are no matters pending as of March 31, 2012 which are expected to have a material adverse impact on our financial position or results of operations.

13. Condensed consolidating financial information

As of March 31, 2012 and December 31, 2011, we had $460.0 million of 9.00% senior notes due November 2018 (the "Senior Notes"). These notes are guaranteed by certain of our wholly owned subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of March 31, 2012:

Atlantic Power Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, 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

Table of Contents

13. Condensed consolidating financial information (Continued)

Power Services, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Auburndale, LLC, Auburndale LP, LLC, Auburndale GP, LLC, Badger Power Generation I, LLC, Badger Power Generation, II, LLC, Badger Power Associates, LP, 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, Atlantic Oklahoma Wind, LLC, and Teton Operating Services, LLC.

In addition, as of March 31, 2012, Curtis Palmer, LLC, fully and unconditionally guaranteed Atlantic Power Limited Partnership's guarantee of the Senior Notes.

The following condensed consolidating financial information presents the financial information of Atlantic Power, the guarantor subsidiaries and Curtis Palmer LLC in accordance with Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or Curtis Palmer LLC 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.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

March 31, 2012

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

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Assets					
Current Assets:					
Cash and cash equivalents	$ 100,827	$ (78)	$ 5,860	$	$ 106,609
Restricted cash	27,761				27,761
Accounts receivable	89,392	17,477	2,996	(50,364)	59,501
Prepayments, supplies, and other	39,555	1,167	1,139		41,861
Other current assets	4,055		8,856		12,911
Total current assets	261,590	18,566	18,851	(50,364)	248,643
Property, plant, and equipment, net	1,375,605	175,087		(1,066)	1,549,626
Transmission system rights	178,319				178,319
Equity investments in unconsolidated affiliates	5,053,320		865,104	(5,441,326)	477,098
Other intangible assets, net	582,491	166,067		(150,925)	597,633
Goodwill	285,358	58,228			343,586
Other assets	483,401		438,639	(841,235)	80,805
Total assets	$ 8,220,084	$ 417,948	$ 1,322,594	$ (6,484,916)	$ 3,475,710
Liabilities					
Current Liabilities:					
Accounts payable and accrued liabilities	$ 99,992	$ 4,704	$ 38,672	$ (50,364)	$ 93,004
Revolving credit facility	22,800		50,000		72,800
Current portion of long-term debt	246,520				246,520
Other current liabilities	51,308		13,468		64,776
Total current liabilities	420,620	4,704	102,140	(50,364)	477,100
Long-term debt	714,685	190,000	460,000		1,364,685
Convertible debentures			193,269		193,269
Other non-current liabilities	1,214,271	8,135	948	(841,235)	382,119
Equity					
Preferred shares issued by a subsidiary company	221,304				221,304
Common shares	5,094,502	208,991	1,217,893	(5,303,493)	1,217,893
Accumulated other comprehensive income (loss)	12,216				12,216
Retained deficit	539,619	6,118	(651,656)	(289,824)	(395,743)

Total Atlantic Power Corporation shareholders' equity	5,867,641	215,109	566,237	(5,593,317)	1,055,670
Noncontrolling interest	2,867				2,867
Total equity	5,870,508	215,109	566,237	(5,593,317)	1,058,537
Total liabilities and equity	$ 8,220,084	$ 417,948	$ 1,322,594	$ (6,484,916)	$ 3,475,710

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended March 31, 2012

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

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 157,118	$ 10,617	$	$ (125)	$ 167,610
Project expenses:					
Fuel	62,099				62,099
Project operations and maintenance	30,067	1,636	(128)	(75)	31,500
Depreciation and amortization	32,705	3,763			36,468
	124,871	5,399	(128)	(75)	130,067
Project other income (expense):					
Change in fair value of derivative instruments	(58,122)				(58,122)
Equity in earnings of unconsolidated affiliates	2,947				2,947
Interest expense, net	(4,325)	(2,708)			(7,033)
Other income, net	15				15
	(59,485)	(2,708)			(62,193)
Project income	(27,238)	2,510	128	(50)	(24,650)
Administrative and other expenses (income):					
Administration expense	5,134		2,699		7,833
Interest, net	20,379		1,484	173	22,036
Foreign exchange loss	1,133		(147)		986
	26,646		4,036	173	30,855
Income (loss) from operations before income taxes	(53,884)	2,510	(3,908)	(223)	(55,505)
Income tax expense (benefit)	(16,291)				(16,291)
Net income (loss)	(37,593)	2,510	(3,908)	(223)	(39,214)
Net loss attributable to noncontrolling interest	(161)				(161)
Net income attributable to Preferred share dividends of a subsidiary company	3,239				3,239
Net income (loss) attributable to Atlantic Power Corporation	$ (40,671)	$ 2,510	$ (3,908)	$ (223)	$ (42,292)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Three months ended March 31, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net cash provided by operating activities	$ 30,019	$ (46)	$ 36,519	$	$ 66,492
Cash flows used in investing activities:					
Acquisitions and investments, net of cash acquired	198		(198)		
Change in restricted cash	(6,349)				(6,349)
Biomass development costs	(123)				(123)
Purchase of property, plant and equipment	(164,126)	(17)			(164,143)
Net cash used in investing activities	(170,400)	(17)	(198)		(170,615)
Cash flows provided by financing activities:					
Repayment for long-term debt	(2,725)				(2,725)
Deferred finance costs	(10,179)				(10,179)
Proceeds from project-level debt	184,216				184,216
Payments for revolving credit facility borrowings	(8,000)				(8,000)
Proceeds from revolving credit facility borrowings	22,800				22,800
Dividends paid	(3,274)		(32,757)		(36,031)
Net cash provided by financing activities	182,838		(32,757)		150,081
Net increase in cash and cash equivalents	42,457	(63)	3,564		45,958
Cash and cash equivalents at beginning of period	58,370	(15)	2,296		60,651
Cash and cash equivalents at end of period	$ 100,827	$ (78)	$ 5,860	$	$ 106,609

Table of Contents

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:

- the amount of distributions expected to be received from the projects;
- matters related to the purchase of the Company's 7,462,830.33 common membership interests in PERH;
- matters related to the Canadian Hills acquisition;
- the ability of the Company to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due; and
- expectations regarding completion of construction of certain projects.

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. 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. 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 discussed under "Risk Factors" included in the filings we make from time to time with the SEC. Our business is both competitive and subject to various risks.

These risks include, without limitation:

- a reduction in revenue upon 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 impact of significant environmental and other regulations on our projects;
- increased competition, including for acquisitions; and
- our limited control over the operation of certain minority owned projects.

Other factors, such as general economic conditions, including exchange rate fluctuations, also may have an effect on the results of our operations. 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.

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

Table of Contents

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 Form 10-Q, 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 thousands of U.S. dollars, unless otherwise stated. The interim financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

Overview of Our Business

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. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,397 MW in which our aggregate ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 operational power generation projects across 11 states in the United States and two provinces in Canada and a 500-kilovolt 84-mile electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. We also own a majority interest in Rollcast Energy, a biomass power plant developer in North Carolina, and a 14.3% common equity interest in PERH. Twenty-three of our projects are wholly owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 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 under steam sales agreements to industrial and commercial purchasers. The transmission system rights we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, 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 not an effective pass-through of fuel costs, we attempt to mitigate a significant portion of the market price risk of fuel purchases through the use of hedging strategies.

While we operate and maintain more than half of our power generation fleet, we also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Caithness Energy, LLC, Colorado Energy Management, Power Plant Management Services and Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Table of Contents

We revised our reportable business segments during the fourth quarter of 2011 upon completion of the Partnership acquisition. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Our financial results for the three months ended March 31, 2011 have been presented to reflect these changes in our operating segments.

RECENT DEVELOPMENTS

Canadian Hills

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and a wholly owned subsidiary of Atlantic Power, 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 298.45 MW wind energy project under construction 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. At the time, we also closed a $310 million non-recourse, project-level construction financing facility for the project. The facility includes a $290 million construction loan and a $20 million 5-year letter of credit facility. Proceeds from the construction loan were used, in part, to repay Atlantic Power $29.3 million in member loans that were made to the project to fund construction prior to closing the construction financing facility. The construction loan is structured to be repaid with a tax equity investment, in which we are actively pursuing, when institutional investors at the time Canadian Hills commences commercial operations.

In connection with the closing of the construction financing facility on March 30, 2012, we committed to invest approximately $180 million in equity (net of financing costs) to cover the balance of the construction and development costs, expected to be drawn following the final disbursement of the construction loan. We anticipate funding our equity commitment with the proceeds of one or more financing arrangements, including offerings of convertible debentures and common stock, borrowings under our revolving credit facility or other senior debt facilities or issuances, or a combination thereof. The sources of financing for our equity commitment will depend upon a variety of factors, including market conditions. We have received an approximately $360 million bridge facility commitment to provide flexibility in the timing of the tax equity and permanent capital raise.

Canadian Hills executed power PPAs for all of its output with Southwestern Electric Power Company (201.25 MW), Oklahoma Municipal Power Authority (49.2 MW), and Grand River Dam Authority (48 MW).

PERH Interest Sale

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("PERC"), whereby PERC will purchase our 14.3% common membership interests in PERH for approximately $24 million, plus a management agreement termination fee of approximately $6.1 million for a total price of $30.1 million. The transaction remains subject to pricing adjustment or termination under certain circumstances. Completion of the transaction is subject to PERC obtaining financing and is expected to occur in the second quarter of 2012.

Path 15

In February 2011, we filed a rate application with the Federal Energy Regulatory Commission ("FERC") to establish Path 15's revenue requirement at $30.3 million for the 2011-2013 period. On March 7, 2012, Path 15 filed a formal settlement agreement establishing a revenue requirement at $28.8 million with the Administrative Law Judge for her review and certification to FERC for approval.

Table of Contents

All of the parties in the rate case either support or do not oppose the settlement agreement. Path 15 expects an order approving the settlement from FERC during the second quarter of 2012.

DuPont Litigation

In December 2008, the Chambers project, which is accounted for under the equity method of accounting, filed suit against DuPont de Nemours & Company ("DuPont") for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, the Chambers project received a favorable ruling from the court on its summary judgment motion as to liability. The court's decision included a description of the pricing methodology that is consistent with the project's position. On April 25, 2012, the court issued its written opinion which ordered DuPont to pay Chambers a total of approximately $15.7 million. This amount represents DuPont's electricity underpayments from January 2003 through June 2009, and interest through July 22, 2011. The court also ordered that from July 1, 2009 going forward, the pricing methodology should be calculated in accordance with the court's prior ruling on summary judgment. DuPont has until June 9, 2012 to file an appeal. The amount of such underpayments including interest is estimated at approximately $10.6 million.

OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of May 2, 2012, 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.

Table of Contents

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	2028	BBB-
Chambers	New Jersey	Coal	262	40.00%	105	ACE	2024	BBB+
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Schering-Plough Corporation	2012	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	2027	A-
Selkirk	New York	Natural Gas	345	17.70%	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Calstock	Ontario	Natural Gas	35	100.00%	35	Ontario Electricity Financial Corp	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2022	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Tunis	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	2014	AA-
Southeast Segment								
Auburndale	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+

Pasco	Florida	Natural Gas	121	100.00%	121	Tampa Electric Company	2018	BBB
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013	NR
Piedmont	Georgia	Biomass	54	98.0%	53	Georgia Power	2032	A
Northwest Segment								
Mamquam	British Columbia	Hydro	50	100.00%	50	British Columbia Hydro and Power Authority	2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00%	6	British Columbia Hydro and Power Authority	2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00%	66	British Columbia Hydro and Power Authority	2018	AAA
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Rockland Wind Project	Idaho	Wind	80	30.00%	24	Idaho Power Co.	2036	BBB
Frederickson	Washington	Natural Gas	250	50.15%	125	Benton Co. PUD, Grays Harbor PUD, Franklin Co. PUD	2022	A
Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Southwest Segment								
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2013	BBB+
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	2019	A
North Island	California	Natural Gas	40	100.00%	40	San Diego Gas & Electric	2019	A

Oxnard	California	Natural Gas	40	100.00%	40	Southern California Edison	2020	BBB+
Path 15	California	Transmssion	N/A	100.00%	N/A	California Utilities via CAISO	N/A	BBB+ to A
Greeley	Colorado	Natural Gas	72	100%	72	Public Service Company of Colorado	2013	A-
Manchief	Colorado	Natural Gas	300	100%	300	Public Service Company of Colorado	2022	A-
Morris	Illinois	Natural Gas	177	100%	77	Merchant	2023	NR
					100	Equistar Chemicals, LP		B+
Delta-Person	New Mexico	Natural Gas	132	40.0%	53	Public Service Company of New Mexico	2020	BBB-
Canadian Hills	Oklahoma	Wind	300	99.0%	200	Southwestern Electric Power Company	2032	BBB
					49	Oklahoma Municial Power Authority	2037	NR
					48	Grand River Dam Authority	2032	NR
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing & Trading	2013	A-
					9	Sherwin Alumina	2020	NR

Table of Contents

Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2012 and 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31,		
(in thousands of U.S. dollars)	**2012**	**2011**	**$ change**
Project revenue			
Northeast	$ 66,926	$ 4,547	62,379
Southeast	41,751	41,426	325
Northwest	15,300		15,300
Southwest	42,696	7,644	35,052
Un-allocated Corporate	937	48	889
	167,610	53,665	113,945
Project expenses			
Northeast	47,177	3,695	43,482
Southeast	30,167	31,735	(1,568)
Northwest	13,947		13,947
Southwest	34,418	3,047	31,371
Un-allocated Corporate	4,358	542	3,816
	130,067	39,019	91,048
Project other income (expense)			
Northeast	(57,794)	(1,084)	(56,710)
Southeast	129	3,397	(3,268)
Northwest	557	57	500
Southwest	(5,061)	(2,146)	(2,915)
Un-allocated Corporate	(24)	(1)	(23)
	(62,193)	223	(62,416)
Total project (loss) income			
Northeast	(38,045)	(232)	(37,813)
Southeast	11,713	13,088	(1,375)
Northwest	1,910	57	1,853
Southwest	3,217	2,451	766
Un-allocated Corporate	(3,445)	(495)	(2,950)
	(24,650)	14,869	(39,519)
Administrative and other expenses			
Administration	7,833	4,054	3,779
Interest, net	22,036	3,968	18,068
Foreign exchange loss (gain)	986	(658)	1,644
Total administrative and other expenses	30,855	7,364	23,491
Income (loss) from operations before income taxes	(55,505)	7,505	(63,010)
Income tax expense (benefit)	(16,291)	1,523	(17,814)
Net (loss) income	(39,214)	5,982	(45,196)
Net loss attributable to noncontrolling interest	(161)	(154)	(7)
Preferred share dividends of a subsidiary company	3,239		3,239
Net (loss) income attributable to Atlantic Power Corporation	$ (42,292)	$ 6,136	$ (48,428)

Consolidated Overview

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The consolidated results of operations are discussed below by reportable segment. The consolidated results of operation for the three months ended March 31, 2012 include the results of operation from the Partnership, which was acquired on November 5, 2011.

Table of Contents

Project income is the primary GAAP measure of our operating results and is discussed in "Segment Analysis" below. In addition, an analysis of non-project expenses impacting our results is set out in "Un-allocated Corporate" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that 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); (2) the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar denominated obligations; and (3) the related deferred income tax expense (benefit) associated with these non-cash items.

Cash Available for Distribution was $59.8 million and $16.6 million for the three months ended March 31, 2012 and 2011, respectively. Cash Available for Distribution is a non-GAAP financial measure that we believe is a relevant supplemental measure of our ability to pay dividends to our shareholders. See "Supplementary Non-GAAP Financial Information" and "Cash Available for Distribution" below for additional information.

Income (loss) from operations before income taxes for the three months ended March 31, 2012 and 2011 was $(55.5) million and $7.5 million, respectively. See "Segment Analysis" below for additional information.

Segment Analysis

Northeast

The following table summarizes project income for our Northeast segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Income	$ (38,045)	$ (232)	Not meaningful ("NM")

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project income for the three months ended March 31, 2012 decreased $37.8 million from the comparable 2011 period primarily due to:

- decreased project income of $49.1 million from the newly acquired North Bay, Kapuskasing and Nipigon projects. The project income for these projects were impacted by a $57.9 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives during the first quarter of 2012.

These decreases were partially offset by:

- project income from the newly acquired Curtis Palmer project of $2.5 million and Tunis project of $4.3 million; and

- increased project income of $5.1 million at Selkirk attributable to lower operations and maintenance costs, higher capacity revenue and a $1.3 million non-cash change in the fair value of gas supply agreements from the comparable 2011 period.

Table of Contents

Southeast

The following table summarizes project income for our Southeast segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Income	$ 11,713	$ 13,088	-11%

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project income for the three months ended March 31, 2012 decreased $1.4 million or 11% from the comparable 2011 period primarily due to:

- decreased project income of $2.2 million at Auburndale primarily attributable to a decrease of $2.6 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps;
- decreased project income of $1.2 million at Lake primarily attributable to a decrease of $0.8 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps; and
- decreased project income of $1.0 million at Orlando primarily due to a $1.4 million non-cash change in fair value of derivative instruments associated with its natural gas swaps offset by contractual escalation of capacity revenue.

These decreases were partially offset by:

- increased project income of $1.0 million at Piedmont due to a non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing; and
- increased project income of $2.0 million at Pasco due to an unplanned replacement of gas turbine components and repairs during the comparable 2011 period.

Northwest

The following table summarizes project income for our Northwest segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project Income	$ 1,910	$ 57	NM

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project income for the three months ended March 31, 2012 increased $1.8 million from the comparable 2011 period primarily due to:

- project income of $0.8 million from the newly acquired Mamquam project;
- project income of $0.6 million from the newly acquired Williams Lake project; and

project income of $0.6 million from the newly acquired Frederickson project.

Table of Contents

Southwest

The following table summarizes project income for our Southwest segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Income	$ 3,217	$ 2,451	31%

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project income for the three months ended March 31, 2012 increased $0.8 million or 31% from the comparable 2011 period primarily due to:

- project income of $3.3 million from the newly acquired Morris project.

This increase was partially offset by:

- decreased project income of $2.1 million at Gregory attributable to higher operations and maintenance costs due to a planned outage during the first quarter of 2012 that was longer than anticipated.

Un-allocated Corporate

The following table summarizes the results of operations for the Un-allocated Corporate segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Un-Allocated Corporate			
Project loss	$ (3,445)	$ (495)	596%
Administration	7,833	4,054	93%
Interest, net	22,036	3,968	455%
Foreign exchange loss (gain)	986	(658)	-250%
Total administrative and other expenses	$ 30,855	$ 7,364	319%
Income tax expense (benefit)	$ (16,291)	$ 1,523	-1170%

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Total administrative and other expenses for the three months ended March 31, 2012 increased $23.5 million or 319% from the comparable 2011 primarily due to:

- increased administration expense of $3.8 million primarily due to the costs of administration subsequent to the acquisition of the Partnership;

- increased interest expenses of $18.1 million primarily due to issuance of the Senior Notes in the fourth quarter of 2011 as well as debt assumed in our acquisition of the Partnership; and

- increased foreign exchange loss of $1.6 million primarily due to a $12.6 million increase in unrealized loss on foreign exchange forward contracts and a $1.6 million decrease in unrealized losses in the revaluation of instruments denominated in

Canadian dollars offset by a $9.4 million increase in realized gains on foreign exchange contract settlements. The U.S. dollar to Canadian dollar exchange rate decreased by 1.9% in the three months ended March 31, 2012 compared to a decrease of 2.5% in the comparable 2011 period.

Table of Contents

Income tax benefit for the three months ended March 31, 2012 was $16.3 million. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $13.9 million for the three months ended March 31, 2012 is primarily due to taxable losses in higher state and local tax jurisdictions

Supplementary Non-GAAP Financial Information

The 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 net cash provided by operating activities 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 and 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 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 unaudited 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 to Project Adjusted EBITDA is set out below by segment under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Project Adjusted EBITDA (in thousands of U.S. dollars)

	Three months ended March 31,		$ change
	2012	**2011**	**2012 vs 2011**
Project Adjusted EBITDA by segment			
Northeast	$ 42,398	$ 7,488	$ 34,910
Southeast	21,674	19,588	2,086
Northwest	13,439	866	12,573
Southwest	18,764	8,501	10,263
Un-allocated Corporate	(3,424)	(450)	(2,974)
Total	92,851	35,993	56,858
Reconciliation to project income			
Depreciation and amortization	49,945	17,437	32,508
Interest expense, net	8,868	6,240	2,628
Change in the fair value of derivative instruments	58,422	(2,784)	61,206
Other (income) expense	266	231	35
Project income	$ (24,650)	$ 14,869	$ (39,519)

Table of Contents

Northeast

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

	The months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Adjusted EBITDA	$ 42,398	$ 7,488	NM

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project Adjusted EBITDA for the three months ended March 31, 2012 increased $34.9 million or 466% from the comparable 2011 period primarily due to:

- increased Project Adjusted EBITDA of $3.5 million at Selkirk due to lower O&M costs and higher capacity revenue from the comparable 2011 period;
- Project Adjusted EBITDA of $9.0 million at the newly acquired Curtis Palmer project;
- Project Adjusted EBITDA of $5.4 million at the newly acquired Tunis project; and
- Project Adjusted EBITDA of $4.8 million at the newly acquired North Bay project.

Southeast

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

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Adjusted EBITDA	$ 21,674	$ 19,588	11%

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project Adjusted EBITDA for the three months ended March 31, 2012 increased $2.1 million or 11% from the comparable 2011 period primarily due to:

- a $2.0 million increase in Project Adjusted EBITDA at Pasco, which had higher operations and maintenance expenses in the comparable 2011 period attributable to the unplanned replacement of gas turbine blades during a maintenance outage.

Northwest

The following table summarizes project adjusted EBITDA for our Northwest segment for the periods indicated:

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project Adjusted EBITDA	$ 13,439	$ 866	NM

Table of Contents

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project Adjusted EBITDA for the three months ended March 31, 2012 increased $12.6 million from the comparable 2011 period primarily due to:

- increased Project Adjusted EBITDA of $1.0 million at Idaho Wind which became fully operational late in the first quarter of 2011;

- Project Adjusted EBITDA of $6.4 million from newly acquired Williams Lake project; and

- Project Adjusted EBITDA of $3.1 million from newly acquired Frederickson project.

Southwest

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

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Adjusted EBITDA	$ 18,764	$ 8,501	NM

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Project Adjusted EBITDA for the three months ended March 31, 2012 increased $10.3 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $4.4 million from the newly acquired Manchief project;

- Project Adjusted EBITDA of $4.0 million from the newly acquired Morris project; and

- Project Adjusted EBITDA of $2.4 million from the newly acquired Naval Station, Naval Training Center and North Island projects.

These increases were partially offset by:

- decreased Project Adjusted EBITDA of $2.0 million at Gregory attributable to higher operations and maintenance costs due to a planned outage during the first quarter of 2012 that was longer than anticipated.

Table of Contents

Generation and Availability

	Three months ended March 31,		
	2012	2011	% change 2012 vs. 2011
Aggregate power generation (Net MWh)			
Northeast	665,193	207,640	220.4%
Southeast	459,272	430,325	6.7%
Northwest	248,048	22,991	978.9%
Southwest	580,392	158,385	266.4%
Total	1,952,905	819,341	138.4%
Weighted average availability			
Northeast	98.6%	80.5%	22.5%
Southeast	98.5%	99.3%	-0.8%
Northwest	93.2%	97.7%	-4.5%
Southwest	93.2%	94.6%	-1.4%
Total	96.3%	93.8%	2.7%

Three months ended March 31, 2012 compared with three months ended March 31, 2011

Aggregate power generation for the three months ended March 31, 2012 increased 138.4% from the comparable 2011 period primarily due to:

- increased generation in the Northeast segment primarily due to 505,546 MWh from the newly acquired Partnership projects;
- increased generation in the Southeast segment attributable to the Pasco project that had an unplanned outage in the first quarter of 2011;
- increased generation in the Northwest segment primarily due to 193,785 MWh from the newly acquired Partnership projects as well as generation from Rockland which became operational in the first quarter of 2012; and
- increased generation in the Southwest segment primarily due to 474,630 MWh from the newly acquired Partnership projects offset by decreased generation at Gregory due to a planned outage which lasted longer than anticipated.

Weighted average availability for the three months ended March 31, 2012 increased 2.7% from the comparable 2011 period primarily due to:

- increased availability in the Northeast segment primarily due to increases at Chambers and Selkirk that had planned outages in the comparable 2011 period;

This increase was partially offset by:

- decreased availability in the Northwest segment primarily due to a planned outage at Mamquam; and
- decreased availability in the Southwest segment primarily due to the planned outage at Gregory.

Consolidated Cash Flows

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 $66.4 million provided by operating activities and $150.1 million of cash provided by financing activities, offset by and $170.6 million of cash used in investing activities.

Table of Contents

At March 31, 2011, cash and cash equivalents decreased $17.2 million from December 31, 2010 to $28.3 million. The decrease in cash and cash equivalents was due to $18.1 million used in investing activities and $19.5 million used in financing activities offset by $20.3 million of cash provided by operating activities.

	Three months ended March 31,		$ Change
	2012	2011	2012 vs. 2011
Net cash provided by operating activities	$ 66,492	$ 20,347	$ 46,145
Net cash used in investing activities	(170,615)	(18,115)	(152,500)
Net cash provided by (used in) financing activities	150,081	(19,471)	169,552

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 flows from operating activities increased by $46.1 million for the three months ended March 31, 2012 over the comparable period in 2011. 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 flows used in investing activities for the three months ended March 31, 2012 were $170.6 million compared to cash flows used in investing activities of $18.1 million for the comparable 2011 period. The change is primarily attributable to $163.4 million of construction in progress related to the Piedmont and Canadian Hills projects.

Financing Activities

Cash provided by financing activities for the three months ended March 31, 2012 resulted in a net inflow of $150.1 million compared with a $19.5 million outflow for the comparable 2011 period. The change is primarily due to $176.1 million of proceeds from the Canadian Hills construction loan, partially offset by an increase in dividend payments attributable to shares issued in connection with the acquisition of the Partnership and the dividend increase that was effective in November 2011.

Table of Contents

Cash Available for Distribution

Initially in 2011, holders of our common shares received a monthly cash dividends at an annual rate of Cdn$1.094 per share. This dividend was increased to an annual rate of Cdn$1.15 per share in November 2011 upon the closing of the Partnership acquisition. The payout ratio associated with the dividend was 55% and 114% for the three months ended March 31, 2012 and 2011, respectively. 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. 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, 2012 and 2011:

(unaudited) **(in thousands of U.S. dollars, except as otherwise stated)**	**Three months ended March 31,** **2012**	**2011**
Cash flows from operating activities	$ 66,492	$ 20,347
Project-level debt repayments	(2,725)	(3,400)
Purchases of property, plant and equipment	(716)	(338)
Dividends on preferred shares of a subsidiary company	(3,239)	
Cash Available for Distribution[1]	59,812	16,609
Total dividends declared to shareholders	$ 32,780	$ 18,992
Payout ratio	55%	114%
Expressed in Cdn$		
Cash Available for Distribution	59,882	16,407
Total dividends declared to shareholders	32,667	18,623

(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.

Liquidity and Capital Resources

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion 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. 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.

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.

Table of Contents

With the exception of our equity contribution of approximately $180 million towards the construction of the Canadian Hills project, we do not expect any material unusual requirements for cash outflows for 2012 for capital expenditures or other required investments. In addition, there are no debt instruments, other than the construction loan for Canadian Hills, with significant maturities or refinancing requirements in 2012. As discussed earlier, we expect to pay down the construction loan facility at Canadian hills with proceeds from our $180 equity investment and proceeds from tax equity investments from institutional investors.

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. Ongoing 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 million in 2012 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. 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 as a result of the timing of more infrequent events such as steam turbine overhauls, and gas turbine and hydroelectric turbine upgrades.

In 2012, several of our projects will conduct scheduled outages to complete major maintenance work. The level of maintenance and capital expenditures for our legacy portfolio of projects will be consistent with prior years. However, overall maintenance and capital expenditures will be higher than in 2011 due to our acquisition of the Partnership project portfolio. During the first quarter of 2012 the level of maintenance expense was substantial, including outage related work performed at the Chambers, Gregory, Kapuskasing and Nipigon facilities, and capital expenditures were minimal which is customary.

In all cases, maintenance outages occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

In the first quarter of 2012, we incurred approximately $8.1 million in capital expenditures for the construction of our Piedmont biomass project. In 2012, we expect to incur a total of approximately $35.2 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million.

In the first quarter of 2012, we also incurred $154.8 million in capital expenditures for the construction of our Canadian Hills Wind project. We expect to incur approximately $470 million in total construction costs with an expected completion in the fourth quarter of 2012.

Senior Credit Facility

On November 4, 2011, we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $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 0.75% and 3.00% that varies based on our corporate credit rating. The credit facility matures on November 4, 2015.

The credit facility contains representations, warranties, terms and conditions customary for credit facilities of this type. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. The credit facility is secured by pledges of certain assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

As of May 2, 2012, $50.0 million has been drawn under the credit facility and the applicable margin was 2.75%. As of May 2, 2012, $139.1 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects, which include the newly acquired projects from the Partnership acquisition.

Notes of Atlantic Power

On November 4, 2011, we completed a private placement of $460.0 million aggregate principal amount of 9.0% senior notes due 2018 ("Senior Notes") to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The Senior Notes were issued at an issue price of 97.471% of the face amount of the Senior Notes for aggregate gross proceeds to us of $448.0 million. The Senior Notes are senior unsecured obligations, guaranteed by certain of our subsidiaries.

Notes of the Partnership

The Partnership, a wholly owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($210.5 million at March 31, 2012) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (the "Partnership Notes"). Interest on the Partnership Notes is payable semi-annually at 5.95%. Pursuant to the terms of the Partnership Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Partnership Notes are guaranteed by Atlantic Power Preferred Equity Ltd,, an indirect, wholly owned subsidiary acquired in connection with the acquisition of the Partnership.

Notes of Atlantic Power (US) GP

Atlantic Power (US) GP, an indirect, wholly owned subsidiary acquired in connection with the acquisition of the Partnership, has outstanding $150.0 million aggregate principal amount of 5.87% senior guaranteed notes, Series A, due August 2017 (the "Series A Notes"). Interest on the Series A Notes is payable semi-annually at 5.87%. Atlantic Power (US) GP has also outstanding $75.0 million aggregate principal amount of 5.97% senior guaranteed notes, Series B, due August 2019 (the "Series B Notes"). Interest on the Series B Notes is payable semi-annually at 5.97%. Pursuant to the terms of the Series A Notes and the Series B Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership and Atlantic Power (US) GP. The Series A Notes and the Series B Notes are guaranteed by the Partnership and by Curtis Palmer LLC.

Notes of Curtis Palmer LLC

Curtis Palmer LLC has outstanding $190.0 million aggregate principal amount of 5.90% senior unsecured notes, due July 2014 (the "Curtis Palmer Notes"). Interest on the Curtis Palmer Notes is payable semi-annually at 5.90%. Pursuant to the terms of the Curtis Palmer Notes, we must meet

Table of Contents

certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Curtis Palmer Notes are guaranteed by the Partnership.

Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.50% convertible secured debentures, which we refer to as the 2006 Debentures, for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 2006 Debentures have a maturity date of October 31, 2014 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. Through May, 2012, Cdn$15.1 million of the 2006 Debentures were converted to 1.1 million common shares. There were no conversions during 2012. As of May 2, 2012 the 2006 Debentures balance is Cdn$44.9 million ($45.5 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures, for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. Through May 2, 2012, Cdn$18.8 million of the 2009 Debentures were converted to 1.4 million common shares. There were no conversions during 2012. As of May 2, 2012 the 2009 Debentures balance is Cdn$67.4 million ($68.4 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures, for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of May 2, 2012 the 2010 Debentures balance is Cdn$80.5 million ($81.6 million).

Preferred shares issued by Atlantic Power Preferred Equity Ltd.

In 2007, Atlantic Power Preferred Equity Ltd., ("APPEL") a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. On or after June 30, 2012, the Series 1 Shares are redeemable by APPEL at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, APPEL issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares are redeemable by APPEL at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares

Table of Contents

will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of APPEL, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of APPEL, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of APPEL. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

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, 2012 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, 2012, the covenants at the Selkirk, Gregory, Delta-Person and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect to resume receiving distributions from Selkirk in the second quarter of 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. All project-level debt is non-recourse to us and substantially the entire 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.

Table of Contents

The range of interest rates presented represents the rates in effect at March 31, 2012. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2012	2013	2014	2015	2016	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 34,608	$ 1,125	$ 3,000	$ 5,000	$ 5,750	$ 6,000	$ 13,733
Piedmont[(1)]	3.80% 5.20%	108,863		55,357	4,789	4,772	3,690	40,255
Canadian Hills[(2)]	3.30%	176,149	176,149					
Path 15	7.9% 9.0%	145,880	8,667	9,402	8,065	8,749	9,487	101,510
Auburndale	5.10%	10,150	5,250	4,900				
Cadillac	6.40% 8.00%	39,631	1,800	2,400	2,000	3,891	2,500	27,040
Curtis Palmer[(3)]	5.90%	190,000			190,000			
Total Consolidated Projects		705,281	192,991	75,059	209,854	23,162	21,677	182,538
Equity Method Projects:								
Chambers	1.70% 7.60%	61,127	9,200	10,783	5,780	5,213	5,447	24,704
Delta-Person	1.90%	8,883	703	1,300	1,394	1,495	1,604	2,387
Selkirk	9.00%	5,845	5,845					
Gregory	2.40% 7.70%	12,115	1,346	2,007	2,170	2,268	2,448	1,876
Rockland	6.4	26,105	434	368	445	529	583	23,746
Idaho Wind	3.10% 6.60%	50,365	1,529	2,198	2,364	2,554	2,511	39,209
Total Equity Method Projects		164,440	19,057	16,656	12,153	12,059	12,593	91,922
Total Project-Level Debt		$ 869,721	$ 212,048	$ 91,715	$ 222,007	$ 35,221	$ 34,270	$ 274,460

(1) As of March 31, 2012 the inception to date balance of $108.9 million on the Piedmont construction debt is funded by the related bridge loan of $51.0 million and $57.9 million funded by the construction loan that will convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations, and an $82.0 million construction term loan. The $51.0 million bridge loan will be repaid in early 2013 and repayment of the expected $82.0 million term loan will commence in 2013.

(2) Canadian Hills debt outstanding is funded by a $290.0 million construction loan. The facility is expected to be repaid in late 2012 by the tax equity funding.

(3) The Curtis Palmer Notes are not considered non-recourse project-level debt and these notes are guaranteed by the Partnership.

Restricted Cash

The projects with project-level debt generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. At March 31, 2012, restricted cash at the consolidated projects totaled $27.8 million.

Recently Adopted and Recently Issued Accounting Guidance

See Note 1 to the consolidated financial statements in Part I Item 1 of this Form 10-Q.

Off-Balance Sheet Arrangements

As of March 31, 2012, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel 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.

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. 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 Tunis project is exposed to changes in natural gas prices under a combination of spot purchases and short-term contracts expiring in 2014. In 2012, projected cash distributions at Tunis would change by approximately $2.8 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.

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. In the third quarter of 2010, we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. 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.

We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because both projected natural gas prices at that time and the prices in the natural gas swaps we have executed are lower than the price of natural gas being purchased under the project's gas contract.

The Lake project's operating margin is exposed to changes in the market price of natural gas from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA on July 31, 2013 not passed through in their PPAs. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

In 2012, projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas

Table of Contents

volumes at the project. In 2012, projected cash distributions at Auburndale would change by approximately $0.4 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

Coal prices used in the energy revenue component of the projected distributions from the Lake and Auburndale projects incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions from Lake and Auburndale combined would change by approximately $2.4 million for every $0.25/Mmbtu change in the projected price of coal.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of March 31, 2012 and May 2, 2012:

	2012	2013
Portion of gas volumes currently hedged:		
Lake:		
Contracted		
Financially hedged	90%	83%
Total	90%	83%
Auburndale:		
Contracted	32%	
Financially hedged	32%	79%
Total	64%	79%
Average price of financially hedged volumes (per Mmbtu)		
Lake	$ 6.90	$ 6.63
Auburndale	$ 6.53	$ 6.92

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 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 the long-term sustainability 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 approximately 85% 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, 2012, 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$123.0 million at an average exchange rate of Cdn$1.127 per U.S. dollar. It is our intention to periodically consider extending or terminating the length of these forward contracts.

On January 4, 2012, we terminated various foreign currency forward contracts with expiration dates through December 2013 assumed in our acquisition of the Partnership resulting in a realized gain of $9.6 million. On May 1, 2012, we terminated additional currency forward contracts that resulted in a $1.1 million realized gain being recorded in the quarter ended June 30, 2012.

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

Table of Contents

foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the three months ended March 31, 2012 and 2011:

	Three months ended March 31,	
	2012	2011
Unrealized foreign exchange (gain) loss:		
Convertible debentures	$ 3,706	$ 5,314
Forward contracts and other	9,210	(3,436)
	12,916	1,878
Realized foreign exchange loss (gains) on forward contract settlements	(11,930)	(2,536)
	$ 986	$ (658)

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, 2012:

Canadian dollar denominated debt, at carrying value	$ (19,327)
Foreign currency forward contracts	$ 25,170

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 83% 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.

We have executed an interest rate swap at our consolidated Auburndale project to economically fix a portion of 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 Auburndale debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

We have an interest rate swap at our consolidated Cadillac project to economically fix a portion of 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. The interest rate swap expires on June 30, 2025.

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 were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, 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. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive

Table of Contents

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. 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 earnings until the expected transaction occurs.

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $3.4 million.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we 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 of the end of the period covered by this report, our principal executive officer and principal financial officer 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 first quarter of 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Our Lake project is currently involved in a dispute with PEF over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by PEF. The Lake project has filed a claim against Progress in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. PEF filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods and our forward guidance for distributions does not include proceeds from off-peak sales, pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

On May 29, 2011, our Morris facility was struck by lightning. As a result, steam and electric deliveries were interrupted to our host Equistar. We believe the interruption constitutes a force majeure under the energy services agreement with Equistar. Equistar disputes this interpretation and has initiated arbitration proceedings under the agreement for recovery of resulting lost profits and equipment damage among other items. The agreement with Equistar specifically shields Morris from exposure to consequential damages incurred by Equistar and management expects our insurance to cover any material losses we might incur in connection with such proceedings, including settlement costs. Management will attempt to resolve the arbitration through settlement discussions, but is prepared to vigorously defend the arbitration on the merits.

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of March 31, 2012 that are expected to have a material impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

Other than as described below, there were no material changes to the risk factors disclosed in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2011 (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 Part I, "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations").

Our Canadian Hills project is subject to construction risk.

Our Canadian Hills project commenced construction in April 2012 and is expected to be completed and begin commercial operations in late 2012. In any construction project, there is a risk that circumstances occur which prevent its timely completion, cause construction costs to exceed the level budgeted or result in operating performance standards not being met.

In the event Canadian Hills does not begin commercial operations by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which matures at the start of commercial operation. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA. To the

Table of Contents

extent actual construction costs of the project exceed estimates, we will have to contribute additional funds in order to complete construction. We have entered into contracts with our turbine suppliers and balance of plant contractor which contain terms and conditions (e.g. liquidated damages provisions) designed to mitigate those risks.

In addition, the federal government provides economic incentives to the owners of wind energy facilities such as Canadian Hills. As provided by the American Recovery and Reinvestment Act of 2009, the owners of qualifying wind energy facilities placed in service before the end of 2012 are eligible for production tax credits in the form of a ten-year tax credit against federal income tax obligations. In the event Canadian Hills (or some subset of Wind Turbines) are not placed in service by the end of 2012 and Congress does not extend the production tax credit provision, this could have a material adverse effect on the project's financial condition. Moreover, upon the commencement of commercial operations, we currently expect to repay outstanding amounts under the $310 million construction loan facility for the project with the proceeds of tax equity investments by institutional investors. If we do not qualify for production tax credits, however, we will be unable to secure the same amount of tax equity investments for the project and will need to seek alternative form of financing for the project. We may be unable to secure alternative forms of financing on favorable terms or at all.

At the completion of construction, Canadian Hills may not meet its expected operating performance levels or prove to be accretive to our cash flow from operations. Adverse circumstances may impact the design, construction, and commissioning of the project that could result in reduced output or other unfavorable results. Any of these risks could adversely affect the cash flow, financial position and results of operations of Canadian Hills, and could adversely affect our cash available for dividends to stockholders.

If financing for our Canadian Hills project is unavailable, we may not be able to complete construction of the project.

Pursuant to the terms of the Canadian Hills' construction financing facility, we have agreed to make equity contributions in aggregate amount of $180 million to Canadian Hills to finance the project construction and development costs in excess of the borrowings available under the financing facility. While we do not need to begin making our equity contributions until the construction loan facility is drawn down in full, we are required thereafter to make our equity contributions as necessary to meet construction draws as they occur. The precise required timing and amount of the draws depends upon the progress of the project construction, which will be subject to a variety of contingencies, many of which will be beyond our control.

We anticipate funding our equity commitment with the proceeds of one or more financing arrangements, including offerings of convertible debentures and common shares, borrowings under our revolving credit facility or other senior debt facilities or issuances, or a combination thereof. The sources of financing for our equity commitment will depend upon a variety of factors, including market conditions, and we may not be able to complete securities offerings successfully or at all. In addition, borrowings under our existing revolving credit facility may only be used to fund our equity commitment in Canadian Hills with the consent of the applicable lenders under that facility. While we have received an approximately $360 million bridge facility commitment from Morgan Stanley to provide flexibility in the timing of the tax equity and permanent capital raise. Draws on this facility are subject to meeting covenants under our existing revolving credit facility. Funding under the bridge facility is also subject to certain conditions, including, without limitation, that there shall not have occurred a material adverse effect with respect to us (or Canadian Hills). If the bridge facility were to be drawn down and not repaid within one year, refinancing terms could be unfavorable and have an adverse impact on the Company. In the event that the lenders under our existing revolving credit facility or the bridge facility fail to provide or consent to funding for any reason, we may not be able to complete construction of

Table of Contents

the Canadian Hills project in a timely manner or at all, which would have a material adverse effect on our financial condition and results of operations.

ITEM 6. EXHIBITS

Exhibit Number	Description
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Label Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

** Furnished herewith.

XBRL information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

Table of Contents

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 7, 2012	Atlantic Power Corporation		
	By:	/s/ LISA J. DONAHUE	
		Name:	Lisa J. Donahue
		Title:	*Interim Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*