ATLANTIC POWER CORP
Form 10-Q
August 12, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

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

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

The number of shares outstanding of the registrant's Common Stock as of August 10, 2011 was 68,963,203.

ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND SIX MONTHS ENDED JUNE 30, 2011

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GENERAL

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

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

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	June 30, 2011 (unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 46,551	$ 45,497
Restricted cash	21,034	15,744
Accounts receivable	20,028	19,362
Note receivable related party (Note 14)	7,326	22,781
Current portion of derivative instruments asset (Notes 8 and 9)	9,297	8,865
Prepayments, supplies, and other	8,451	8,480
Refundable income taxes	1,611	1,593
Total current assets	114,298	122,322
Property, plant, and equipment, net	308,051	271,830
Transmission system rights	184,208	188,134
Equity investments in unconsolidated affiliates (Note 4)	276,962	294,805
Other intangible assets, net	77,425	88,462
Goodwill	12,453	12,453
Derivative instruments asset (Notes 8 and 9)	18,865	17,884
Other assets	16,718	17,122
Total assets	$ 1,008,980	$ 1,013,012
Liabilities		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 16,333	$ 20,530
Current portion of long-term debt (Note 6)	21,962	21,587
Current portion of derivative instruments liability (Notes 8 and 9)	7,410	10,009
Interest payable on convertible debentures (Note 7)	1,948	3,078
Dividends payable	6,490	6,154
Other current liabilities	7	5
Total current liabilities	54,150	61,363
Long-term debt (Note 6)	263,111	244,299
Convertible debentures (Note 7)	209,703	220,616
Derivative instruments liability (Notes 8 and 9)	24,822	21,543
Deferred income taxes	23,594	29,439
Other non-current liabilities	2,121	2,376
Commitments and contingencies (Note 15)		

Total liabilities	577,501	579,636
Equity		
Common shares, no par value, unlimited authorized shares; 68,639,654 and 67,118,154 issued and outstanding at June 30, 2011 and December 31, 2010 , respectively	644,001	626,108
Accumulated other comprehensive income (Note 9)	24	255
Retained deficit	(215,782)	(196,494)
Total Atlantic Power Corporation shareholders' equity	428,243	429,869
Noncontrolling interest	3,236	3,507
Total equity	431,479	433,376
Total liabilities and equity	$ 1,008,980	$ 1,013,012

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Project revenue:				
Energy sales	$ 17,865	$ 16,659	$ 36,367	$ 32,572
Energy capacity revenue	27,651	23,195	54,789	46,389
Transmission services	7,491	7,729	15,135	15,373
Other	251	321	632	791
	53,258	47,904	106,923	95,125
Project expenses:				
Fuel	14,316	15,771	31,384	31,928
Operations and maintenance	7,801	6,442	18,873	12,402
Depreciation and amortization	10,924	10,071	21,803	20,142
	33,041	32,284	72,060	64,472
Project other income (expense):				
Change in fair value of derivative instruments (Notes 8 and 9)	(4,574)	992	(1,013)	(11,202)
Equity in earnings of unconsolidated affiliates	1,962	3,026	3,273	8,462
Interest expense, net	(4,543)	(4,308)	(9,190)	(8,719)
Other income (expense), net	(31)	211	(33)	211
	(7,186)	(79)	(6,963)	(11,248)
Project income	13,031	15,541	27,900	19,405
Administrative and other expenses (income):				
Administration	4,671	3,843	8,725	7,943
Interest, net	3,510	2,518	7,478	5,312
Foreign exchange (gain) loss (Note 9)	(535)	4,224	(1,193)	2,432
Other income, net		(26)		(26)
	7,646	10,559	15,010	15,661
Income from operations before income taxes	5,385	4,982	12,890	3,744
Income tax expense (benefit) (Note 10)	(7,684)	3,618	(6,161)	8,491
Net income (loss)	13,069	1,364	19,051	(4,747)
Net loss attributable to noncontrolling interest	(117)	(81)	(271)	(129)
Net income (loss) attributable to Atlantic Power Corporation	$ 13,186	$ 1,445	$ 19,322	$ (4,618)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 12)				
Basic	$ 0.19	$ 0.02	$ 0.28	$ (0.08)
Diluted	$ 0.18	$ 0.02	$ 0.28	$ (0.08)

Weighted average number of common shares outstanding: (Note 12)				
Basic	68,573	60,481	68,116	60,443
Diluted	82,939	60,890	82,973	60,443

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

(Unaudited)

	Six months ended June 30, 2011	Six months ended June 30, 2010
Cash flows from operating activities:		
Net income (loss)	$ 19,051	$ (4,747)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	21,803	20,142
Long-term incentive plan expense	1,639	2,149
Gain on step-up valuation of Rollcast acquisition		(211)
Equity in earnings from unconsolidated affiliates	(3,273)	(8,462)
Distributions from unconsolidated affiliates	11,584	5,718
Unrealized foreign exchange loss	4,499	5,199
Change in fair value of derivative instruments	1,013	11,202
Change in deferred income taxes	(5,691)	7,416
Change in other operating balances		
Accounts receivable	(666)	(953)
Prepayments, refundable income taxes and other assets	1,244	(481)
Accounts payable and accrued liabilities	(4,996)	(1,970)
Other liabilities	(1,492)	976
Net cash provided by operating activities	44,715	35,978
Cash flows used in by investing activities:		
Acquisitions and investments, net of cash acquired		324
Change in restricted cash	(5,290)	280
Proceeds from sale of equity investments	8,500	
Repayments from related party loan	15,455	
Biomass development costs	(587)	(948)
Purchase of property, plant and equipment	(42,898)	(1,520)
Net cash used in investing activities	(24,820)	(1,864)
Cash flows used in by financing activities:		
Proceeds from project-level debt	29,890	
Repayment of project-level debt	(10,341)	(9,141)
Equity investment from noncontrolling interest		200
Proceeds from revolving credit facility borrowings		20,000
Dividends paid	(38,390)	(31,709)
Net cash used in financing activities	(18,841)	(20,650)
Net increase in cash and cash equivalents	1,054	13,464
Cash and cash equivalents at beginning of period	45,497	49,850
Cash and cash equivalents at end of period	$ 46,551	$ 63,314
Supplemental cash flow information		
Interest paid	$ 17,600	$ 11,437
Income taxes paid (refunded), net	$ (436)	$ 1,045

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of presentation and summary of significant accounting policies

Overview

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, 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 1,948 megawatts (or "MW") in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. Six of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P., Cadillac Renewable Energy, LLC, Piedmont Green Power, LLC and Atlantic Path 15, LLC.

The interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission ("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 consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2010. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly our consolidated financial position as of June 30, 2011, the results of operations for the three and six-month periods ended June 30, 2011 and 2010, and our cash flows for the six-month periods ended June 30, 2011 and 2010.

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 period. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements ("PPAs"), the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the valuation of shares associated with our long-term incentive plan 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 if indications of impairment exist during the period. These estimates and 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 assumptions and estimates change, the recorded amounts could change by a material amount.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Reclassifications:

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

Recently issued accounting standards:

Adopted

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. Upon adoption, we determined these changes did not impact the consolidated financial statements.

In December 2010, the FASB issued changes to the testing of goodwill for impairment. These changes require an entity to perform all steps in the test for a reporting unit whose carrying value is zero or negative if it is more likely than not (more than 50%) that a goodwill impairment exists based on qualitative factors, resulting in the elimination of an entity's ability to assert that such a reporting unit's goodwill is not impaired and additional testing is not necessary despite the existence of qualitative factors that indicate otherwise. We adopted these changes beginning January 1, 2011. Based on the most recent impairment review of our goodwill (2010 fourth quarter), we determined these changes did not impact the consolidated financial statements.

In January 2010, the FASB issued changes to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose, in the reconciliation of fair value measurements using significant unobservable inputs (Level 3), separate information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number) of these Level 3 financial instruments. We adopted these changes beginning January 1, 2011. We determined that these changes did not have an impact on the consolidated financial statements.

In April 2010, the FASB issued changes to the classification of certain employee share-based payment awards. These changes clarify that there is not an indication of a condition that is other than market, performance, or service if an employee share-based payment award's exercise price is denominated in the currency of a market in which a substantial portion of the entity's equity securities trade and differs from the functional currency of the employer entity or payroll currency of the employee. An employee share-based payment award is required to be classified as a liability if the award does not contain a market, performance, or service condition. These changes were adopted beginning on January 1, 2011. We determined that these changes did not have an impact on the consolidated financial statements.

Issued

In May 2011, the FASB issued changes 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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. These changes become effective on January 1, 2012. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

In June 2011, the FASB issued changes 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 stockholders' 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. These changes become effective on January 1, 2012. We are currently evaluating these changes to determine which option will be chosen for the presentation of comprehensive income. Other than the change in presentation, we have determined these changes will not have an impact on the consolidated financial statements

2. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss) for the three and six-month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Net income (loss)	$ 13,069	$ 1,364	$ 19,051	$ (4,747)
Unrealized gain (loss) on hedging activity	(107)	652	1,097	992
less income tax (benefit) expense	(43)	261	439	397
Comprehensive income (loss)	$ 13,005	$ 1,755	$ 19,709	$ (4,152)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Acquisitions and divestitures

(a)
Capital Power Income L.P.

On June 20, 2011, Atlantic Power, Capital Power Income L.P. ("CPILP"), CPI Income Services Ltd., the general partner of CPILP, and CPI Investments Inc., a unitholder of CPILP that is owned by EPCOR Utilities Inc. and Capital Power Corporation, entered into the Arrangement Agreement, which provides that Atlantic Power will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to the Plan of Arrangement under the Canada Business Corporations Act. Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, Cdn$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately Cdn$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power, for approximately Cdn$121.0 million which equates to approximately Cdn$2.15 per unit of CPILP. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power and CPILP and certain of its subsidiaries will be terminated (or assigned) in consideration of a payment of Cdn$10.0 million. Atlantic Power or its subsidiaries will assume the management of CPILP and enter into a transitional services agreement with Capital Power for a term of 6 to 9 months following the completion of the Plan of Arrangement, which will facilitate the integration of CPILP into Atlantic Power.

The Arrangement Agreement contains customary representations, warranties and covenants. Among these covenants, CPILP and CPI Income Services Ltd. have each agreed not to solicit alternative transactions, except that CPILP may respond to an alternative transaction proposal that constitutes, or would reasonably expect to lead to, a superior proposal that we would have the right to match. In addition, Atlantic Power or CPILP may be required to pay a Cdn$35.0 million fee if the Arrangement Agreement is terminated in certain unlikely circumstances.

The completion of the Plan of Arrangement is subject to the receipt of all necessary court and regulatory approvals in Canada and the United States and certain other closing conditions. Atlantic Power and CPILP currently expect to complete the Plan of Arrangement in the fourth quarter of 2011, subject to receipt of required shareholder/unitholder, court and regulatory approvals and the satisfaction or waiver of the financing and other conditions to the Plan of Arrangement described in the Arrangement Agreement.

(b)
Topsham

On February 28, 2011, we entered into a purchase and sale agreement with an affiliate of ArcLight Capital Partners, LLC ("ArcLight") for the purchase of our lessor interest in the project. The transaction closed on May 6, 2011 and we received proceeds of $8.5 million, resulting in no gain or loss on the sale.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Equity method investments

The following summarizes the operating results for the three and six months ended June 30, 2011 and 2010, respectively, for our equity earnings interest in our equity method investments:

	Three-months ended June 30,		Six-months ended June 30,	
	2011	2010	2011	2010
Revenue				
Chambers	13,009	13,329	26,278	28,746
Badger Creek	1,334	3,213	4,655	7,103
Gregory	7,633	7,687	14,814	16,553
Orlando	9,375	10,321	19,302	20,760
Selkirk	12,961	12,564	23,861	26,043
Other	3,132	1,930	4,952	3,170
	47,444	49,044	93,862	102,375
Project expenses				
Chambers	9,545	10,026	18,925	20,292
Badger Creek	1,414	2,755	4,398	6,225
Gregory	6,900	6,472	13,530	14,697
Orlando	9,605	9,869	19,068	19,915
Selkirk	12,631	11,921	25,289	24,749
Other	2,366	1,349	3,795	2,443
	42,461	42,392	85,005	88,321
Project other income (expense)				
Chambers	(663)	(844)	(1,090)	(1,751)
Badger Creek	(7)	193	(11)	195
Gregory	(194)	(891)	(231)	(685)
Orlando	(13)	(33)	(44)	(66)
Selkirk	(929)	(1,988)	(2,566)	(3,087)
Other	(1,215)	(63)	(1,642)	(198)
	(3,021)	(3,626)	(5,584)	(5,592)
Project income (loss)				
Chambers	2,801	2,459	6,263	6,703
Badger Creek	(87)	651	246	1,073
Gregory	539	324	1,053	1,171
Orlando	(243)	419	190	779
Selkirk	(599)	(1,345)	(3,994)	(1,793)
Other	(449)	518	(485)	529
	1,962	3,026	3,273	8,462

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. 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 June 30, 2011 and December 31, 2010:

	June 30, 2011	December 31, 2010
Property, plant and equipment	$ 98,248	$ 91,851
Transmission system rights	47,461	43,535
Other intangible assets	68,472	57,000

6. Long-term debt

Long-term debt represents project-level long-term debt of our consolidated subsidiaries and the unamortized balance of purchase accounting adjustments that were recorded in connection with the Path 15 acquisition in order to adjust the debt to its fair value on the acquisition date. Project-level debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	June 30, 2011	December 31, 2010
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 274,131	$ 254,581
Purchase accounting fair value adjustments	10,942	11,305
Less: current portion of long-term debt	(21,962)	(21,587)
Long-term debt	$ 263,111	$ 244,299

Project-level debt is secured by the respective project and its contracts with no other recourse to us. The loans have certain financial covenants that must be met. At June 30, 2011, all of our projects were in compliance with the covenants contained in the project-level debt. However, the holding company for our investment in the Chambers project, Epsilon Power Partners and the Delta-Person project 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.

As of June 30, 2011 the inception to date balance on the Piedmont construction debt funded by the related bridge loan was $29.9 million. The Piedmont debt outstanding is funded by the bridge loan. The terms of the Piedmont project-level debt refinancing include an $82.0 million construction and term loan and 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. The $51.0 million bridge loan will be repaid in 2012 and repayment of the expected $82.0 million term loan will commence in 2013.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Convertible debentures

The following table contains details related to outstanding convertible debentures:

	6.5% Debentures due 2014	6.25% Debentures due 2017	5.6% Debentures due 2017
Balance at December 31, 2010 (Cdn$)	55,801	83,124	80,500
Principal amount converted to equity (Cdn$)	(8,899)	(8,267)	
Balance at June 30, 2011 (Cdn$)	46,902	74,857	80,500
Balance at June 30, 2011 (US$)	48,628	77,612	83,463
Common shares issued on conversion during the six-months ended June 30, 2011	717,653	635,919	

Aggregate interest expense related to the convertible debentures was $3.0 million and $2.1 million for the three-month periods ended June 30, 2011 and 2010, respectively, and $6.4 million and $4.4 million for the six-month periods ended June 30, 2011 and 2010, respectively.

8. Fair value of financial instruments

The following represents our financial assets and liabilities that were recognized at fair value as of June 30, 2011 and December 31, 2010. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 46,551	$	$	$ 46,551
Restricted cash	21,034			21,034
Derivative instruments asset		28,162		28,162
Total	$ 67,585	$ 28,162	$	$ 95,747
Liabilities:				
Derivative instruments liability	$	$ 32,232	$	$ 32,232
Total	$	$ 32,232	$	$ 32,232

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 45,497	$	$	$ 45,497
Restricted cash	15,744			15,744
Derivative instruments asset		26,749		26,749
Total	$ 61,241	$ 26,749	$	$ 87,990
Liabilities:				
Derivative instruments liability	$	$ 31,552	$	$ 31,552
Total	$	$ 31,552	$	$ 31,552

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Fair value of financial instruments (Continued)

The fair value of our derivative instruments are based on price quotes from brokers in active markets who regularly facilitate those transactions and we believe such price quotes are executable. We adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating or the credit rating of our counterparties. As of June 30, 2011, the credit reserve resulted in a $0.6 million net increase in fair value, which is attributable to a $0.4 million pre-tax gain in other comprehensive income and a $0.4 million gain in change in fair value of derivative instruments, partially offset by a $0.2 million loss in foreign exchange. As of December 31, 2010, the credit reserve resulted in a $0.6 million net increase in fair value, which is attributable to a $0.2 million pre-tax gain in other comprehensive income and a $0.5 million gain in change in fair value of derivative instruments, partially offset by a $0.1 million loss in foreign exchange.

9. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

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

	June 30, 2011	
	Derivative Assets	**Derivative Liabilities**
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,923
Interest rate swaps long-term		2,914
Total derivative instruments designated as cash flow hedges		4,837
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,317
Interest rate swaps long-term	2,580	2,910
Foreign currency forward contracts current	9,297	
Foreign currency forward contracts long-term	16,285	
Natural gas swaps current		3,170
Natural gas swaps long-term		18,998
Total derivative instruments not designated as cash flow hedges	28,162	27,395
Total derivative instruments	$ 28,162	$ 32,232

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2010 Derivative Assets	December 31, 2010 Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 2,124
Interest rate swaps long-term		2,626
Total derivative instruments designated as cash flow hedges		4,750
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		1,286
Interest rate swaps long-term	3,299	2,000
Foreign currency forward contracts current	8,865	
Foreign currency forward contracts long-term	14,585	
Natural gas swaps current		6,599
Natural gas swaps long-term		16,917
Total derivative instruments not designated as cash flow hedges	26,749	26,802
Total derivative instruments	$ 26,749	$ 31,552

Natural gas swaps

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 which 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.

In October 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In 2014, both the projected natural gas prices and the prices of these natural gas swaps are lower than the current price of natural gas being purchased under the project's gas contract. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando project at a weighted average price of $5.76/Mmbtu and represent approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. These swap agreements were entered into by us and not at the project level. Orlando is accounted for under the equity method of accounting.

Our strategy to mitigate the future exposure to changes in natural gas prices at Lake, Auburndale and Orlando 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 its 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 agreement. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 3.12%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

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.

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 consolidated statements of operations. 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 which will convert to a term loan. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

Impact of derivative instruments on the consolidated income statements

Unrealized gains (losses) on interest rate swaps designated as cash flow hedges have been recorded, net of tax, in shareholders' equity in other comprehensive income as a loss of $0.1 million and a gain of $0.4 million for the three-month periods ended June 30, 2011 and 2010, respectively, and a gain of $0.7 million and $0.6 million for the six-month periods ended June 30, 2011 and 2010 respectively. Settlements of these interest rate swaps of $0.6 million and $0.4 million were recorded in interest expense, net for the three-month periods ended June 30, 2011 and 2010, respectively, and $1.2 million and $0.7 million for the six-month periods ended June 30, 2011 and 2010, respectively.

Unrealized gains and losses on natural gas swaps previously designated as cash flow hedges are recorded in other comprehensive income. In the period in which the unrealized gains and losses are settled, the cash settlement payments are recorded as fuel expense. A $5.1 million loss was recorded 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 in other comprehensive income of $(0.2) million and $0.4 million was recorded in change in fair value of derivative instruments for the three-month periods ended

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

June 30, 2011 and 2010, respectively, and $(0.3) million and $0.8 million for the six-month periods ended June 30, 2011 and 2010, respectively.

Unrealized gains and losses on derivative instruments not designated as cash flow hedges are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

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

	Classification of (gain) loss recognized in income	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Natural gas swaps	Fuel	$ 2,055	$ 2,621	$ 4,531	$ 4,439
Foreign currency forwards	Foreign exchange (gain) loss	(3,155)	(1,599)	(5,692)	(2,767)
Interest rate swaps	Interest, net	955	474	1,931	949

Unrealized gains and losses associated with changes in the fair value of derivative instruments not designated as cash flow hedges and ineffectiveness of derivatives designated as cash flow hedges are reflected in current period earnings. The following table summarizes the pre-tax gains and (losses) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Change in fair value of derivative instruments:				
Interest rate swaps	$ (3,337)	$ (120)	$ (2,659)	$ (166)
Natural gas swaps	(1,237)	1,112	1,646	(11,036)
	$ (4,574)	$ 992	$ (1,013)	$ (11,202)

Volume of forecasted transactions

We 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 June 30, 2011:

	Units	June 30, 2011
Interest rate swaps	Interest (US$)	$ 55,147
Currency forwards	Dollars (Cdn$)	$ 181,900
Natural gas swaps	Natural Gas (Mmbtu)	13,660

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 but pay dividends to shareholders and interest on 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 by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. 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. 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) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts.

The foreign exchange forward contracts are recorded at fair value based on quoted market prices and our estimation of the counterparty's credit risk. The fair value of our forward foreign currency contracts is $25.6 million and $23.4 million at June 30, 2011 and December 31, 2010, respectively. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the three and six-month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Unrealized foreign exchange (gain) loss:				
Convertible debentures	$ 1,317	$ (6,486)	$ 6,632	$ (2,505)
Forward contracts and other	1,303	12,309	(2,133)	7,704
	2,620	5,823	4,499	5,199
Realized foreign exchange gains on forward contract settlements	(3,155)	(1,599)	(5,692)	(2,767)
	$ (535)	$ 4,224	$ (1,193)	$ 2,432

The following table illustrates the impact on our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of June 30, 2011:

Convertible debentures, at carrying value	$ 20,970
Foreign currency forward contracts	$ (20,548)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2011	$ (66)	$ 593	$ 527
Change in fair value of cash flow hedges	(64)		(64)
Realized from OCI during the period	(349)	(90)	(439)
Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24

For the three month period ended June 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2010	$ (554)	$ (73)	$ (627)
Change in fair value of cash flow hedges	391		391
Realized from OCI during the period	(211)	253	42
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)

For the six month period ended June 30, 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	658		658
Realized from OCI during the period	(710)	(179)	(889)
Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24

For the six month period ended June 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2009	$ (538)	$ (321)	$ (859)
Change in fair value of cash flow hedges	595		595
Realized from OCI during the period	(431)	501	70
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Income taxes

The difference between the actual tax benefit of $7.7 million and $6.2 million for the three and six months ended June 30, 2011, respectively, and the expected income tax expense, based on the Canadian enacted statutory rate of 26.5%, of $1.4 million and $3.4 million, respectively is primarily due to the change in basis of the Idaho Wind assets due to the receipt of the proceeds of the stimulus grant as well as a decrease in the valuation allowance and various other permanent differences.

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Current income tax expense (benefit)	$ 18	$ 1,038	$ (470)	$ 1,075
Deferred tax expense (benefit)	(7,702)	2,580	(5,691)	7,416
Total income tax expense (benefit)	$ (7,684)	$ 3,618	$ (6,161)	$ 8,491

Valuation Allowance

As of June 30, 2011, we have recorded a valuation allowance of $78.4 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.

11. Long-Term Incentive Plan

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2011:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2010	600,981	$ 10.28
Granted	153,094	$ 14.18
Forfeited	(101,559)	$ 11.61
Additional shares from dividends	20,302	$ 10.95
Vested and redeemed	(263,523)	$ 9.40
Outstanding at June 30, 2011	409,295	$ 11.85

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 2011 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, 2010.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Long-Term Incentive Plan (Continued)

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of June 30, 2011:

Weighted average risk free rate of return	0.39% 0.72%
Dividend yield	7.5%
Expected volatility Company	20.5% 25.9%
Expected volatility peer companies	15.2% 92.7%
Weighted average remaining measurement period	1.26 years

12. 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, 2011. 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.

Because we reported a loss for the six months ended June 30, 2010, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

anti-dilutive. The following table sets forth the diluted net income (loss) and potentially dilutive shares utilized in the per share calculation for the three and six month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Numerator:				
Net income (loss) attributable to Atlantic Power Corporation	$ 13,186	$ 1,445	$ 19,322	$ (4,618)
Add: interest expense for potentially dilutive convertible debentures, net[1]	1,931		3,985	
Diluted net income (loss) attributable to Atlantic Power Corporation	15,117	1,445	23,307	(4,618)

(1) The above adjustment for net interest on the potential common shares that would be issued on the conversion of the convertible debentures has been excluded as the impact would be anti-dilutive for the three and six months ended June 30, 2010.

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
Denominator:				
Weighted average basic shares outstanding	68,573	60,481	68,116	60,443
Dilutive potential shares:				
Convertible debentures	14,055	11,473	14,430	11,473
LTIP notional units	311	409	427	402
Potentially dilutive shares	82,939	72,363	82,973	72,318
Diluted EPS	$ 0.18	$ 0.02	$ 0.28	$ (0.08)

Potentially dilutive shares from convertible debentures for the three and six-month periods ended June 30, 2010 have been excluded from fully diluted because their impact would be anti-dilutive.

13. Segment and related information

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets.

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

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

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2011:								
Operating revenues	$ 7,491	$ 20,434	$ 16,844	$ 3,382	$ 0	$ 5,107	$ 0	$ 53,258
Segment assets	207,838	98,152	105,782	37,564	147,572	329,052	83,020	1,008,980
Project Adjusted EBITDA	$ 7,186	$ 11,606	$ 8,424	$ 1,469	$ 4,307	$ 9,862	$ 0	$ 42,854
Change in fair value of derivative instruments		1,145	(297)		200	3,778		4,826
Depreciation and amortization	2,005	4,959	2,290	757	844	6,806		17,661
Interest, net	2,943	282	(2)		1,413	2,452		7,088
Other project (income) expense					201	47		248
Project income	2,238	5,220	6,433	712	1,649	(3,221)		13,031
Interest, net							3,510	3,510
Administration							4,671	4,671
Foreign exchange gain							(535)	(535)
Income (loss) from operations before income taxes	2,238	5,220	6,433	712	1,649	(3,221)	(7,646)	5,385
Income tax expense (benefit)							(7,684)	(7,684)
Net income (loss)	2,238	5,220	6,433	712	1,649	(3,221)	38	13,069

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2010:								
Operating revenues	$ 7,729	$ 19,570	$ 17,842	$ 2,763	$ 0	$ 0	$ 0	$ 47,904
Segment assets	213,904	121,303	115,822	40,620	136,351	131,560	102,964	862,524
Project Adjusted EBITDA	$ 7,062	$ 10,431	$ 7,299	$ 1,002	$ 4,141	$ 8,591	$ 0	$ 38,526
Change in fair value of derivative instruments		597	(1,709)		(207)	1,529		210
Depreciation and amortization	2,095	4,950	2,267	746	839	5,699		16,596
Interest, net	3,096	415	(4)		1,651	939		6,097
Other project (income) expense					204	(122)		82
Project income	1,871	4,469	6,745	256	1,654	546		15,541
Interest, net							2,518	2,518
Administration							3,843	3,843
Foreign exchange loss							4,224	4,224
Other expense, net							(26)	(26)
Income (loss) from operations before income taxes	1,871	4,469	6,745	256	1,654	546	(10,559)	4,982
Income tax expense (benefit)	990						2,628	3,618
Net income (loss)	881	4,469	6,745	256	1,654	546	(13,187)	1,364

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2011:								
Operating revenues	$ 15,135	$ 42,216	$ 33,968	$ 5,902	$ 0	$ 9,702	$ 0	$ 106,923
Segment assets	207,838	98,152	105,782	37,564	147,572	329,052	83,020	1,008,980
Project Adjusted EBITDA	$ 13,756	$ 21,919	$ 16,914	$ 392	$ 9,031	$ 16,835	$ 0	$ 78,847
Change in fair value of derivative instruments		184	(1,862)		(552)	4,272		2,042
Depreciation and amortization	3,979	9,918	4,580	1,514	1,679	13,428		35,098
Interest, net	5,934	595	(5)		2,801	4,003		13,328
Other project (income) expense					400	79		479
Project income	3,843	11,222	14,201	(1,122)	4,703	(4,947)		27,900
Interest, net							7,478	7,478
Administration							8,725	8,725
Foreign exchange gain							(1,193)	(1,193)
Income (loss) from operations before income taxes	3,843	11,222	14,201	(1,122)	4,703	(4,947)	(15,010)	12,890
Income tax expense (benefit)							(6,161)	(6,161)
Net income (loss)	3,843	11,222	14,201	(1,122)	4,703	(4,947)	(8,849)	19,051

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2010:								
Operating revenues	$ 15,373	$ 40,037	$ 34,083	$ 5,632	$ 0	$ 0	$ 0	$ 95,125
Segment assets	213,904	121,303	115,822	40,620	136,351	131,560	102,964	862,524
						3,535		
Project Adjusted EBITDA	$ 14,115	$ 19,802	$ 14,612	$ 2,417	$ 10,129	$ 16,200	$ 0	$ 77,275
Change in fair value of derivative instruments		4,809	6,226		(380)	2,074		12,729
Depreciation and amortization	4,194	9,898	4,536	1,492	1,676	11,186		32,982
Interest, net	6,242	886	(6)		3,327	1,429		11,878
Other project (income) expense					403	(122)		281
Project income	3,679	4,209	3,856	925	5,103	1,633		19,405
Interest, net							5,312	5,312
Administration							7,943	7,943
Foreign exchange gain							2,432	2,432
Other expense, net							(26)	(26)
Income (loss) from operations before income taxes	3,679	4,209	3,856	925	5,103	1,633	(15,661)	3,744
Income tax expense (benefit)	1,739						6,752	8,491
Net income (loss)	1,940	4,209	3,856	925	5,103	1,633	(22,413)	(4,747)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 69% and 14%, respectively, of total consolidated revenues for the three-months ended June 30, 2011 and 77% and 16% for the three-months ended June 30, 2010. Progress Energy Florida and CAISO provide for 70% and 14%, respectively, of total consolidated revenues for the six-months ended June 30, 2011 and 77% and 16% for the six-months ended June 30, 2010. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Related party transactions

On February 28, 2011, we entered into a purchase and sale agreement with an affiliate of ArcLight 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, resulting in no gain or loss on the sale.

During 2010, we made short-term loans totaling $22.8 million to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. Member loans will be paid down with a combination of excess proceeds from the federal stimulus grant after repaying the cash grant facility, funds from a third closing for additional debt and project cash flow. The federal stimulus grant was approved in June of 2011 and the funds have been received. The third closing from additional debt is expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as June 30, 2011). During the six-months ended June 30, 2011, we received $1.2 million in interest payments related to the member loans. As of August 10, 2011, $15.5 million of the loans have been repaid.

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by ArcLight. On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15.0 million, to be satisfied by a payment of $6.0 million that was made at the termination date, and additional payments of $5.0 million, $3.0 million and $1.0 million on the respective first, second and third anniversaries of the termination date. The remaining liability associated with the termination fee is recorded at its estimated fair value of $3.8 million at June 30, 2011. The contract termination liability is being accreted to the final amounts due over the term of these payments.

15. Commitments and contingencies

Our Lake project is currently involved in a dispute with Progress Energy Florida 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 Progress. 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. Progress 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.

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 June 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Subsequent event

On July 27, 2011, August 3, 2011 and August 5, 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to economically hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction.

The July 27, 2011 transactions include a forward purchase of $32.0 million at $0.9460 per Cdn$1.00, a call option to purchase $84.7 million at $0.94565 per Cdn$1.00 and a put option to sell $116.7 million at $0.90 per Cdn$1.00. The August 3, 2011 transactions include a forward purchase of $76.0 million at $0.9665 per Cdn$1.00, a call option to purchase $14.5 million at $0.9665 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00. The August 5, 2011 transactions include a forward purchase of $81.2 million at $0.9872 per Cdn$1.00, a call option to purchase $9.3 million at $0.9872 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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 for the full year 2011 and 2012;
- our expectation of higher operating cash flow in 2012, primarily attributable to increased distributions from Selkirk;
- our expectation of a significant increase in cash distributions from Orlando beginning in 2014;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012;
- the expected resumption of distributions from the holding company on our Chambers project in 2012;
- the expectation of the Piedmont Construction to be completed in late 2012; and
- the expectation to complete the Plan of Arrangement in the fourth quarter.

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;

our limited control over the operation of certain minority owned projects;

the failure to receive, on a timely basis or otherwise, the required approvals by Atlantic Power shareholders, CPILP unitholders and government or regulatory agencies (including the terms of such approvals) for the Plan of Arrangement; and

the risk that a condition to closing of the transaction contemplated by the Arrangement Agreement may not be satisfied.

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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 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 Corporation 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.

OVERVIEW

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, 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 1,948 MW in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. We sell the capacity and energy from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2011 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 purchasers. The transmission system rights (or "TSRs") 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 a pass-through of fuel costs, we use a financial hedging strategy designed to mitigate a portion of the market price risk of fuel purchases.

We partner with recognized leaders in the independent power industry to operate and maintain our projects, including Caithness Energy, LLC, Power Plant Management Services, Delta Power

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Services and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We completed our initial public offering on the Toronto Stock Exchange (TSX: ATP) in November 2004. Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010.

As of August 10, 2011, we had 68,963,203 common shares, Cdn$45.2 million ($47.5 million) principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$72.4million ($76.1 million) principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 million ($84.6 million) principal amount of 5.60% convertible debentures due June 30, 2017 (the "2010 Debentures" and together with the 2006 and 2009 Debentures, the "Debentures") outstanding. The 2006 Debentures, 2009 Debentures and 2010 Debentures are convertible at any time, at the option of the holder, into 80.645, 76.923 and 55.249, respectively, common shares per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40, Cdn$13.00 and Cdn$18.10, respectively, per common share. Holders of common shares currently receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

RECENT DEVELOPMENTS

On June 20, 2011, Atlantic Power, Capital Power Income L.P. ("CPILP"), CPI Income Services Ltd., the general partner of CPILP, and CPI Investments Inc., a unitholder of CPILP that is owned by EPCOR Utilities Inc. and Capital Power Corporation, entered into the Arrangement Agreement, which provides that Atlantic Power will acquire, directly or indirectly, all of the issued and outstanding CPILP units pursuant to the Plan of Arrangement under the Canada Business Corporations Act. Under the terms of the Plan of Arrangement, CPILP unitholders will be permitted to exchange each of their CPILP units for, at their election, Cdn$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections will be subject to proration if total cash elections exceed approximately Cdn$506.5 million and all share elections will be subject to proration if total share elections exceed approximately 31.5 million Atlantic Power common shares.

Pursuant to the Plan of Arrangement, CPILP will sell its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power, for approximately Cdn$121.0 million which equates to approximately Cdn$2.15 per unit of CPILP. Additionally, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power and CPILP and certain of its subsidiaries will be terminated (or assigned) in consideration of a payment of Cdn$10.0 million. Atlantic Power or its subsidiaries will assume the management of CPILP and enter into a transitional services agreement with Capital Power for a term of up to 6 to 9 months following the completion of the Plan of Arrangement, which will facilitate the integration of CPILP into Atlantic Power.

The Arrangement Agreement contains customary representations, warranties and covenants. Among these covenants, CPILP and CPI Income Services Ltd. have each agreed not to solicit alternative transactions, except that CPILP may respond to an alternative transaction proposal that constitutes, or would reasonably expect to lead to, a superior proposal, that we have a right to match. In addition, Atlantic Power or CPILP may be required to pay a Cdn$35.0 million fee if the Arrangement Agreement is terminated in certain unlikely circumstances.

The completion of the Plan of Arrangement is subject to the receipt of all necessary court and regulatory approvals in Canada and the United States and certain other closing conditions. Atlantic Power and CPILP currently expect to complete the Plan of Arrangement in the fourth quarter of 2011, subject to receipt of required shareholder/unitholder, court and regulatory approvals and other conditions to the Plan of Arrangement described in the Arrangement Agreement.

On May 6, 2011 we closed the sale of our 50.0% lessor interest in the Topsham project for $8.5 million, resulting in no gain or loss on the sale.

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OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of August10, 2011, 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.

Project Name	Location (State)	Type	Total MW	Economic Interest[1]	Net MW[2]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
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 Co.	2018	BBB+
Chambers	New Jersey	Coal	262	40.00%	89	ACE[3]	2024	BBB+
					16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	N/A	California Utilities via CAISO[4]	N/A[5]	BBB+ to A[6]
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013[7]	A1[8]
Selkirk	New York	Natural Gas	345	17.70%[9]	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA
					9	Sherwin Alumina	2020	NR
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2012[10]	BBB+

Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	PNM	2020	BB-
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Piedmont(11)	Georgia	Biomass	54	98.00%	53	Georgia Power	2032	A

(1) Except as otherwise noted, economic interest represents the percentage ownership interest in the project held indirectly by Atlantic Power.

(2) Represents our interest in each project's electric generation capacity based on our economic interest.

(3) Includes a separate power sales agreement in which the project and Atlantic City Electric ("ACE") share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(4) California utilities pay transmission access charges to the California Independent System Operator, who then pays owners of Transmission system rights, such as Path 15, in accordance with its annual revenue requirement approved every three years by the Federal Energy Regulatory Commission ("FERC").

(5) Path 15 is a FERC regulated asset with a FERC-approved regulatory life of 30 years: through 2034.

(6) Largest payers of transmission access charges supporting Path 15's annual revenue requirement are Pacific Gas & Electric (BBB+), Southern California Edison (BBB+) and San Diego Gas & Electric (A). The California Independent System Operator imposes minimum credit quality requirements for any participants rated A or better unless collateral is posted per the California Independent System Operator imposed schedule.

(7) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF under the terms of the current agreement.

(8) Fitch rating on Reedy Creek Improvement District bonds.

(9) Represents our residual interest in the project after all priority distributions are paid to us and the other partners, which is estimated to occur in 2012.

(10) Entered into a one-year interim agreement in April 2011.

(11) Project currently under construction and is expected to be completed in late 2012.

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Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and six month periods ended June 30, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

(Unaudited) (in thousands of U.S. dollars, except as otherwise stated)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Project revenue				
Auburndale	$ 20,434	$ 19,570	$ 42,216	$ 40,037
Lake	16,844	17,842	33,968	34,083
Pasco	3,382	2,763	5,902	5,632
Path 15	7,491	7,729	15,135	15,373
Other Project Assets	5,107		9,702	
	53,258	47,904	106,923	95,125
Project expenses				
Auburndale	13,787	14,089	30,215	30,133
Lake	10,710	12,810	21,634	24,007
Pasco	2,670	2,507	7,024	4,707
Path 15	2,310	2,762	5,357	5,452
Chambers			1	
Other Project Assets	3,564	116	7,829	173
	33,041	32,284	72,060	64,472
Project other income (expense)				
Auburndale	(1,427)	(1,012)	(779)	(5,695)
Lake	299	1,713	1,867	(6,220)
Pasco				
Path 15	(2,943)	(3,096)	(5,935)	(6,242)
Chambers	1,649	1,654	4,704	5,103
Other Project Assets	(4,764)	662	(6,820)	1,806
	(7,186)	(79)	(6,963)	(11,248)
Total project income				
Auburndale	5,220	4,469	11,222	4,209
Lake	6,433	6,745	14,201	3,856
Pasco	712	256	(1,122)	925
Path 15	2,238	1,871	3,843	3,679
Chambers	1,649	1,654	4,703	5,103
Other Project Assets	(3,221)	546	(4,947)	1,633
	13,031	15,541	27,900	19,405
Administrative and other expenses				
Administration	4,671	3,843	8,725	7,943
Interest, net	3,510	2,518	7,478	5,312
Foreign exchange loss (gain)	(535)	4,224	(1,193)	2,432
Other income, net		(26)		(26)
Total administrative and other expenses	7,646	10,559	15,010	15,661
Income from operations before income taxes	5,385	4,982	12,890	3,744
Income tax expense (benefit)	(7,684)	3,618	(6,161)	8,491
Net income (loss)	13,069	1,364	19,051	(4,747)
Net loss attributable to noncontrolling interest	(117)	(81)	(271)	(129)

Net income (loss) attributable to Atlantic Power Corporation shareholders	$ 13,186	$ 1,445	$ 19,322	$ (4,618)

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Consolidated Overview

We have six reportable segments: Auburndale, Chambers, Lake, Pasco, Path 15 and Other Project Assets. The results of operations are discussed below by reportable segment.

Project income is the primary GAAP measure of our operating results and is discussed in "Project Operations Performance" below. In addition, an analysis of non-project expenses impacting our results is set out in "Administrative and Other Expenses (Income)" 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 "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 $18.0 million and $7.5 million for the three-months ended June 30, 2011 and 2010, respectively and $34.6 million and $25.3 million for the six-months ended June 30, 2011 and 2010, respectively. See "Cash Available for Distribution" in this Form 10-Q for additional information.

Income from operations before income taxes for the three-months ended June 30, 2011 and 2010 was $5.4 million and $5.0 million, respectively and $12.9 million and $3.7 million for the six-months ended June 30, 2011 and 2010, respectively. See "Project Income" below for additional information.

Three months ended June 30, 2011 compared with three months ended June 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $0.7 million to $5.2 million in the three-month period ended June 30, 2011 from income of $4.5 million in the comparable 2010 period is primarily attributable to the annual contractual escalation of capacity payments under the project's PPA, as well as favorable gas transportation cost compared to 2010.

Lake Segment

Project income for our Lake segment decreased $0.3 million to $6.4 million in the three-month period ended June 30, 2011, from income of $6.7 million in the comparable 2010 period. The decrease is primarily attributable to a $1.4 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. This was partially offset by lower fuel expenses attributable to lower prices on natural gas swaps.

Pasco Segment

Project income for our Pasco segment increased $0.4 million to $0.7 million in the three-month period ended June 30, 2011, from project income of $0.3 million in the comparable 2010 period. The increase is due to higher dispatch compared to 2010 of the project.

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Path 15 Segment

Project income for our Path 15 segment increased $0.3 million to $2.2 million in the three-month period ended June 30, 2011 from $1.9 million in the comparable 2010 period due to decreased operation and maintenance costs.

Chambers Segment

The change in project income for our Chambers segment, which is recorded under the equity method of accounting, was not significant in the three-month period ended June 30, 2011 compared to same period in 2010.

Other Project Assets Segment

Project income for our Other Project Assets segment decreased $3.7 million to a project loss of $(3.2) million for the three-month period ended June 30, 2011 compared to project income of $0.5 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with the non-cash change in fair value of interest rate swaps recorded at fair value;
- increased expense at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul;
- reduced revenue at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement;
- the absence of income from Topsham. The project was sold in May 2011;
- project loss at Idaho Wind of $0.7 million which became operational in Q1 2011; offset by
- project income of $1.1 million at Cadillac, which was acquired in December 2010.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $0.9 million to $4.7 million in the three-month period ended June 30, 2011 from $3.8 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction and increases in compensation costs attributable to an increase in corporate office staff levels.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $1.0 million to $3.5 million in the three-month period ended June 30, 2011 from $2.5 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss decreased $4.7 million to a $0.5 million gain in the three-month period ended June 30, 2011 compared to a $(4.2) million loss in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 0.5% during the three-month period ended June 30, 2011, compared to a decrease of 4.6% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk

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and the components of the foreign exchange gain recognized during the three-month period ended June 30, 2011 compared to the foreign exchange loss in the comparable 2010 period.

Six months ended June 30, 2011 compared with six months ended June 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $7.0 million to $11.2 million in the six-month period ended June 30, 2011 from income of $4.2 million in the comparable 2010 period is primarily attributable to the $4.6 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. Project revenue at Auburndale increased by $2.1 million in the six-month period ended June 30, 2011 due to favorable energy pricing compared to 2010, as well as the annual contractual escalation of capacity payments. Interest expense on project-level debt decreased by $0.3 million in the six-month period ended June 30, 2011 as compared to the comparable period in 2010.

Lake Segment

Project income for our Lake segment increased $10.3 million to $14.2 million in the six-month period ended June 30, 2011, from income of $3.9 million in the comparable 2010 period. The increase is primarily attributable to the $8.1 million change in the benefit associated with the non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. In addition, fuel costs at Lake decreased due to the lower price on natural gas swaps.

Pasco Segment

Project income for our Pasco segment decreased $2.0 million to a project loss of $(1.1) million in the six-month period ended June 30, 2011, from project income of $0.9 million in the comparable 2010 period. The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components during 2011.

Path 15 Segment

Project income for our Path 15 segment was consistent for the six-month period ended June 30, 2011and 2010.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $0.4 million to $4.7 million in the six-month period ended June 30, 2011 from $5.1 million in the comparable 2010 period. The decrease in project income at Chambers is primarily attributable to lower dispatch compared to 2010.

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Other Project Assets Segment

Project income for our Other Project Assets segment decreased $6.5 million to a project loss of $(4.9) million for the six-month period ended June 30, 2011 compared to project income of $1.6 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with a non-cash change in the fair value of an interest rate swap that is recorded at fair value;

- decreased income at Selkirk due to a planned outage lasting longer than expected that delayed recognition of capacity payments until the third quarter of 2011;

- increased expense at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul;

- reduced revenue at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement;

- the absence of income from Topsham. The project was sold in May 2011;

- project loss at Idaho Wind of $0.6 million which became operational in Q1 2011; offset by

- project income at Cadillac of $1.3 million, which was acquired in December 2010.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $0.8 million to $8.7 million for the six-month period ended June 30, 2011 from $7.9 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction and increased compensation costs attributable to an increase in corporate office staff levels.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $2.2 million to $7.5 million in the six-month period ended June 30, 2011 from $5.3 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss decreased $3.6 million to a $1.2 million gain in the six-month period ended 2011 compared to a $(2.4) million loss in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 3.1% during the six-month period ended June 30, 2011, compared to a decrease of 1.3% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange gain recognized during the six-month period ended June 30, 2011 compared to the foreign exchange loss in the comparable 2010 period.

Supplementary Non-GAAP Financial Information

The key measure we use to evaluate the results of our projects 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

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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, 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 under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Because Project Adjusted EBITDA and project distributions are key drivers of both the performance of our projects and Cash Available for Distribution, please see the following supplementary unaudited non-GAAP information that summarizes Project Adjusted EBITDA by project and a reconciliation of Project Adjusted EBITDA by project to project distributions actually received by us.

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

(unaudited)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Project Adjusted EBITDA by individual segment				
Auburndale	$ 11,606	$ 10,431	$ 21,919	$ 19,802
Lake	8,424	7,299	16,914	14,612
Pasco	1,469	1,002	392	2,417
Path 15	7,186	7,062	13,756	14,115
Chambers	4,307	4,141	9,031	10,129
Total	32,992	29,935	62,012	61,075
Other Project Assets				
Selkirk	3,206	3,526	4,314	7,056
Orlando	1,202	1,870	3,093	3,671
Cadillac	2,644		4,391	
Gregory	956	1,428	1,728	2,283
Idaho Wind	1,246		2,051	
Badger Creek	41	774	801	1,510
Delta Person	443	540	842	904
Koma Kulshan	374	434	434	553
Rollcast	(306)		(773)	
Piedmont	(32)		(61)	
Topsham		548		963
Rumford		1		(7)
Other	88	(530)	15	(733)
Total adjusted EBITDA from Other Project Assets segment	9,862	8,591	16,835	16,200
Total adjusted EBITDA from all Projects	42,854	38,526	78,847	77,275
Depreciation and amortization	17,661	16,596	35,098	32,982
Interest expense, net	7,088	6,097	13,328	11,878
Change in the fair value of derivative instruments	4,826	210	2,042	12,729
Other (income) expense	248	82	479	281
Project income as reported in the statement of operations	$ 13,031	$ 15,541	$ 27,900	$ 19,405

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the six months ended June 30, 2011

	Project Adjusted EBITDA	Repayment of debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 21,919	$ (4,900)	$ (595)	$ (5)	$ (1,619)	$ 14,800
Chambers	9,031	(6,398)	(2,801)		168	
Lake	16,914		5	(447)	2,392	18,864
Pasco	392			(39)	452	805
Path 15	13,756	(3,541)	(5,934)		(2,019)	2,262
Total Reportable Segments	62,012	(14,839)	(9,325)	(491)	(626)	36,731
Other Project Assets						
Selkirk	4,314	(5,354)	(777)	(3)	5,974	4,154
Orlando	3,093		2	(118)	(952)	2,025
Cadillac	4,391	(1,150)	(1,317)	(62)	(662)	1,200
Gregory	1,728	(838)	(231)	(44)	51	666
Idaho Wind	2,051	(33,237)	(1,522)		33,917	1,209
Badger Creek	801		(3)		562	1,360
Delta Person	842	(555)	(120)		(167)	
Koma Kulshan	434				(55)	379
Rollcast	(773)			(4)	777	
Piedmont	(61)				61	
Other	15		(35)	40	180	200
Total Other Project Assets Segment	16,835	(41,134)	(4,003)	(191)	39,686	11,193
Total all Segments	$ 78,847	$ (55,973)	$ (13,328)	$ (682)	$ 39,060	$ 47,924

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the six months ended June 30, 2010

	Project Adjusted EBITDA	Repayment of debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 19,802	$ (4,900)	$ (886)	$ (8)	$ (1,008)	$ 13,000
Chambers	10,129	(6,026)	(3,327)	(34)	(742)	
Lake	14,612		6	(1,004)	748	14,362
Pasco	2,417			(467)	380	2,330
Path 15	14,115	(3,740)	(6,242)		181	4,314
Total Reportable Segments	61,075	(14,666)	(10,449)	(1,513)	(441)	34,006
Other Project Assets						
Selkirk	7,056	(4,657)	(1,181)	(309)	(909)	
Orlando	3,671		1	(66)	(1,706)	1,900
Gregory	2,283	(823)	(112)	(39)	(443)	866
Badger Creek	1,510		(7)		138	1,641
Delta Person	904	(1,023)	(137)		256	
Koma Kulshan	553				(206)	347
Rumford	(7)				7	
Topsham	963					963
Other	(733)		7	(40)	792	26
Total Other Project Assets Segment	16,200	(6,503)	(1,429)	(454)	(2,071)	5,743
Total all Segments	$ 77,275	$ (21,169)	$ (11,878)	$ (1,967)	$ (2,512)	$ 39,749

Project Operations Performance Three months ended June 30, 2011 compared with three months ended June 30, 2010

Aggregate Project Adjusted EBITDA increased $4.4 million to $42.9 million in the three-month period ended June 30, 2011 from $38.5 million in the comparable 2010 period and included the following factors:

- project Adjusted EBITDA of $2.6 million at Cadillac, which was acquired in December 2010;

- project Adjusted EBITDA of $1.2 million at Idaho Wind, which became operational in the first quarter of 2011;

- increased Project Adjusted EBITDA of $1.2 million at Auburndale due to the annual contractual escalation of capacity payments, as well as favorable gas transportation costs;

- increased Project Adjusted EBITDA of $1.1 million at Lake due to decreased fuel costs attributable to the lower prices on natural gas swaps; offset by

- decreased Project Adjusted EBITDA of $0.7 million at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement in April 2011;

decreased Project Adjusted EBITDA of $0.7 million at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul in 2011; and

decreased Project Adjusted EBITDA of $0.5 million at Topsham. The project was sold in May 2011.

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Aggregate power generation for projects in operation for the three-months ended June 30, 2011 was 8.8% greater than the three-month period ended June 30, 2010. Generation during the three-month period ended June 30, 2011 compared to the comparable 2010 period was favorably impacted primarily by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk and Pasco. The favorable variance was partially offset by lower generation at Chambers and Badger Creek due to reduced dispatch, and at Lake which had no off-peak deliveries and a planned major maintenance outage at Orlando in 2011.

The project portfolio achieved a weighted average availability of 95.5% for the three-month period ended June 30, 2011 compared to 95.2% in the 2010 period. The increase in portfolio availability for the three-month period ended June 30, 2011 versus the prior period was primarily due to a planned outage at Selkirk completed in 2010 offset by outages at Orlando and Badger Creek in 2011. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Project Operations Performance Six months ended June 30, 2011 compared with six months ended June 30, 2010

Aggregate Project Adjusted EBITDA increased $1.6 million to $78.9 million in the six-month period ended June 30, 2011 from $77.3 million in the comparable 2010 period and included the following factors:

- project Adjusted EBITDA of $4.4 million at Cadillac, which was acquired in December 2010;
- increased Project Adjusted EBITDA of $2.3 million at Lake due to decreased fuel costs attributable to the lower price on natural gas swaps;
- project Adjusted EBITDA of $2.1 million at Idaho Wind, which became operational in the first quarter of 2011;
- increased Project Adjusted EBITDA of $2.1 million at Auburndale due to the annual contractual escalation of capacity payments and increased dispatch; offset by
- decreased Project Adjusted EBITDA of $2.7 million at Selkirk due to lower capacity revenue. A planned outage was longer than expected and resulted in a delay in recognition of capacity payments until the third quarter of 2011;
- decreased Project Adjusted EBITDA of $2.0 million at Pasco primarily due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine blades during a maintenance outage;
- decreased Project Adjusted EBITDA of $1.1 million at Chambers attributable lower dispatch;
- decreased Project Adjusted EBITDA of $1.0 million at Topsham. The project was sold in May 2011;
- decreased Project Adjusted EBITDA of $0.7 million at Badger Creek primarily attributable to lower capacity payments under the new one year interim power purchase agreement in April 2011;
- decreased Project Adjusted EBITDA of $0.6 million at Orlando due to higher operation and maintenance costs attributable to a planned gas turbine overhaul in 2011;

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- decreased Project Adjusted EBITDA of $0.6 million at Gregory due to lower dispatch and higher fuel costs; and
- decreased Project Adjusted EBITDA of $0.4 million at Path 15 due to higher operation and maintenance costs.

Aggregate power generation for projects in operation for the six-months ended June 30, 2011 was 4.6% greater than the six-month period ended June 30, 2010. Generation during the six-month period ended June 30, 2011 was favorably impacted primarily by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk. The favorable variance was partially offset by lower generation at Chambers and Badger Creek due to reduced dispatch and a planned major maintenance outage at Orlando in 2011 and increased generation at Lake associated with off-peak energy sales in 2010.

The project portfolio achieved a weighted average availability of 94.6% for the six-month period ended June 30, 2011 compared to 96.7% in the 2010 period. The decrease in portfolio availability for the six-month period ended June 30, 2011 versus the prior period was primarily due to planned outages at Badger Creek, Chambers and Selkirk and a forced outage at Delta-Person. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Cash Flow from Operating Activities

Our cash flow from the projects may vary from year to year based on, among other things, changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market or re-contracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the projects. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

Cash flow from operating activities increased by $8.7 million for the six-month period ended June 30, 2011 over the comparable period in 2010. The changes from the prior period are partially attributable to the changes in Project Adjusted EBITDA described above, the release of $4.2 million of previously restricted cash at our equity accounted Selkirk project, as well as changes in working capital at both consolidated and unconsolidated affiliates.

Cash Flow from Investing Activities

Cash flow from investing activities includes 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 six-month period ended June 30, 2011 were $24.8 million compared to cash flows used in investing activities of $1.9 million for the comparable 2010 period. We invested $42.4 million for the construction-in-progress for our Piedmont biomass project offset by the repayment of $15.5 million from our related party loan to Idaho Wind.

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Cash Flow from Financing Activities

Cash used in financing activities for the six-month period ended June 30, 2011 resulted in a net outflow of $18.8 million compared to a net outflow of $20.7 million for the same period in 2010. The change from the comparable period is primarily attributable to a $6.7 million increase in dividends paid due to a higher number of common shares outstanding to the comparable period in 2010. Since the year ended December 31, 2010, Cdn$17.2 million of convertible debentures have converted to common stock. In addition, we issued common shares in a public offering in October 2010. The increase in dividends is partially offset by proceeds of $29.9 million of project-level debt related to our Piedmont biomass project.

Cash Available for Distribution

Holders of our common shares receive monthly cash dividends at an annual rate of Cdn$1.094 per share. Total dividends paid to shareholders for the three and six-month periods ended June 30, 2011 increased over the respective prior year amounts as a result of (i) increases in the value of the Canadian dollar, which is the currency in which the dividends are paid; and (ii) a higher number of common shares outstanding in the 2011 periods as a result of the conversion of convertible debentures into common shares and the issuance of vested shares from our long-term incentive plan. This increase in dividends paid is generally offset by realized gains on our foreign currency forward contracts, which are included in cash flows from operating activities. See "Foreign Currency Exchange Rate Risk" in Item 3 of this Form 10-Q for additional information about our foreign currency forward contracts. The payout ratio for the three-month periods ended June 30, 2011 and 2010 was 109% and 212%, respectively and 111% and 125% for the six-month periods ended June 30, 2011 and 2010, respectively.

The table below presents our calculation of cash available for distribution for the three and six-month periods ended June 30, 2011 and 2010:

(unaudited)	Three months ended June 30,		Six months ended June 30,	
(in thousands of U.S. dollars, except as otherwise stated)	**2011**	**2010**	**2011**	**2010**
Cash flows from operating activities	$ 24,368	$ 15,139	$ 44,715	$ 35,978
Project-level debt repayments	(6,941)	(6,441)	(10,341)	(9,141)
Purchases of property, plant and equipment[1]	(238)	(1,201)	(546)	(1,520)
Transaction costs[2]	768		768	
Cash Available for Distribution[3]	17,957	7,497	34,596	25,317
Total dividends to shareholders	19,550	15,913	38,542	31,714
Payout ratio	109%	212%	111%	125%
Expressed in Cdn$				
Cash Available for Distribution	17,376	7,710	33,793	26,187
Total dividends to shareholders	18,763	16,556	37,386	33,083

(1) Excludes construction-in-progress related to our Piedmont biomass project.

(2) Represents business development costs associated with the CPILP acquisition.

(3) 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".

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Outlook

Based on our actual performance to date and projections for the remainder of the year, we continue to expect to receive distributions from our projects in the range of $80 million to $90 million for the full year 2011. We expect overall levels of operating cash flows in 2011 to be improved over actual 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and Cadillac, and a slightly lower payment under the management termination agreement are expected to be partially offset by the one-time cash tax refund of $8.0 million received in 2010. In 2012, additional increases in distributions from projects are expected to further increase operating cash flow compared to 2011. The most significant factor in the expected higher operating cash flow in 2012 is increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following items comprise the most significant increases in projected 2011 project distributions compared to 2010:

- lower fuel costs at the Lake project;
- resumption of distributions from the Selkirk project;
- annual increase in contractual capacity payments from the Auburndale and Lake projects; and
- distributions from the recently acquired Cadillac and Idaho Wind projects.

In 2010, the following five projects comprised approximately 90% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2011, we expect these same five projects to contribute approximately 85% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2011 and beyond:

Lake

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA in July 2013 that are not passed through its PPAs. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas expected to be purchased at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2013, but do not intend to execute additional hedges at Lake for 2011 and 2012 because our natural gas exposure for those years is already substantially hedged.

The variable energy revenues in the Lake project's PPA are indexed, in part, to the price of coal consumed by a specific utility plant in Florida, the Crystal River facility. The components of this coal price are proprietary to the utility, but we believe that the utility purchases coal for that plant under a combination of short to medium term contracts and spot market transactions.

Coal prices used in the energy revenue component of the projected distributions from the Lake project 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 change by approximately $1.0 million for every $0.25/Mmbtu change in the projected price of coal.

We expect to receive distributions from the Lake project of approximately $30 million to $34 million in both 2011 and 2012. The increases in 2011 and 2012 over the $28.8 million of distributions in 2010 are primarily due to higher contractual capacity payments and lower hedged and unhedged natural gas prices than in 2010.

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Auburndale

Based on the current forecast, we expect distributions from Auburndale of $25 million to $27 million per year from 2011 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2011 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to the costs of coal consumed at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the project's gas supply contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. The 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in 2012 and 2013.

Orlando

The PPA at the Orlando project extends through 2023. However, the project's natural gas supply agreement expires in 2013. Currently projected market prices for natural gas following the expiration of the current supply agreement are lower than the price of natural gas currently being purchased under the project's gas contract. As a result, we expect a significant increase in cash distributions from the Orlando project beginning in 2014. We have been executing a hedging strategy to reduce the market price risk associated with expected natural gas requirements at Orlando in 2014 and beyond. See "Item 3. Quantitative and Qualitative Disclosures About Market Risks" in this Form 10-Q for further details.

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. 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.

Other than the capital requirements stated below for the CPILP acquisition, we do not expect any additional material or unusual requirements for cash outflows for 2011 for capital expenditures or other required investments. We have contributed approximately $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $59.0 million of this amount was contributed in the fourth quarter of 2010 and the remaining balance was paid in the quarter ending March 31, 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2011. See "Outlook" above for information about changes in expected distributions from our projects in 2011 and beyond.

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We intend to finance the cash portion of the purchase price for the transaction with CPILP by issuing up to approximately Cdn$200.0 million of equity and up to approximately $425.0 million of debt through public and private offerings. However, in the event that such financing is not available on terms satisfactory to us, we have received a commitment letter, evidencing the commitment of a Canadian chartered bank and another financial institution to structure, arrange, underwrite and syndicate a senior secured credit facility consisting of a Tranche B Facility in the amount of $625 million, subject to the terms and conditions set forth therein.

Credit facility

We maintain a credit facility with a capacity of $100 million, $50 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

The credit facility bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.5% and 3.35% that varies based on the credit statistics of one of our subsidiaries. As of June 30, 2011, the applicable margin was 1.5%. As of June 30, 2011, $48.6 million were issued in letters of credit, but not drawn, to support contractual credit requirements at eight of our projects.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on the cash flow coverage ratios and also require us to report indebtedness ratios to our lenders. The facility is secured by pledges of 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.

Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures. In 2009 the holders agreed to change the rate to 6.50% and extend the maturity date to 2014. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The 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 August 10, 2011, a cumulative Cdn$14.5 million of the 2006 Debentures have been converted to 1.2 million common shares. As of August 10, 2011 the 2006 Debentures balance is Cdn$45.2 million ($47.5 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. 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 August 10, 2011, a cumulative Cdn$13.9million of the 2009 Debentures have been converted to 1.1 million common shares. As of August 10, 2011 the 2009 Debentures balance is Cdn$72.4 million ($76.1 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. 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

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Cdn$18.10 per common share. As of August 10, 2011 the 2010 debentures balance is Cdn$80.5 million ($84.6 million).

Project-level debt

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at June 30, 2011 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of June 30, 2011, the covenants at the Delta-Person project and at Epsilon Power Partners are temporarily preventing those subsidiaries from making cash distributions to us. We expect to resume receiving distributions from Delta-Person and Epsilon Power Partners in 2012. 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. For the six-month period ended June 30, 2011, we have contributed approximately $0.5 million to Epsilon Power Partners for debt service payments on the holding company debt but do not anticipate any additional required contributions to Epsilon.

The range of interest rates presented represents the rates in effect at June 30, 2011.

	Range of Interest Rates	Total Remaining Principal Repayments	2011	2012	2013	2014	2015	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 35,732	$ 750	$ 1,500	$ 3,000	$ 5,000	$ 5,750	$ 19,732
Piedmont[(1)]	5.20%	29,891		29,891				
Path 15	7.9% - 9.0%	150,327	4,446	8,667	9,402	8,065	8,749	110,998
Auburndale	5.10%	16,800	4,900	7,000	4,900			
Cadillac	6.02% - 8.0%	41,381	1,150	3,791	2,400	2,000	2,500	29,540
Total Consolidated Projects		274,131	11,246	50,849	19,702	15,065	16,999	160,270
Equity Method Projects:								
Chambers	0.9% - 7.0%	69,398	5,647	12,176	10,783	5,780	5,213	29,799
Delta-Person	2.1%	9,966	575	1,212	1,300	1,394	1,495	3,990
Selkirk	9.0%	11,439	5,594	5,845				
Gregory	1.8% - 7.5%	13,510	1,342	1,399	2,007	2,170	2,268	4,324
Idaho Wind[(2)]	5.2% - 13.3%	50,703	8,429	1,848	1,892	2,049	2,136	34,349
Total Equity Method Projects		155,016	21,587	22,480	15,982	11,393	11,112	72,462
Total Project-Level Debt		$ 429,147	$ 32,833	$ 73,329	$ 35,684	$ 26,458	$ 28,111	$ 232,732

(1) The Piedmont debt outstanding is the inception to date balance on the construction debt funded by the related bridge loan. The terms of the Piedmont project-level debt refinancing include an $82.0 million construction and term loan and 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. The $51.0 million bridge loan will be repaid in 2012 and repayment of the expected $82.0 million term loan will commence in 2013.

(2) The Idaho Wind project-level credit facility is composed of two tranches, which include a $157.5 million construction loan that was converted to a 17-year term loan upon commercial operations, and a $83.2 million cash grant facility which was repaid in June with federal stimulus grant proceeds after completion of construction, The remaining costs of the project were funded with a combination of equity from the owners

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and member loans from affiliates of Atlantic Power and GE Energy Financial Services. As of June 30, 2011, our share of total debt outstanding for Idaho Wind was $43.4 million, and our share of the member loans was $7.3 million. Member loans will be paid down with a combination of funds from a third closing for additional debt and project cash flow.

Restricted cash

The projects 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 June 30, 2011, restricted cash at the consolidated projects totaled $21.0 million.

Capital Expenditures

Capital expenditures for the projects are generally made 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 projects in which we have investments generally 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.

In 2011, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is slightly higher than in 2010. During the second quarter of 2011, Badger Creek replaced the combustor section of its gas turbine, the cost of which was covered under the operations and maintenance fee to the project's operator. Orlando undertook a scheduled major overhaul of its gas turbine and a major overhaul of its steam turbine in the second quarter. A substantial portion of Orlando's outage costs are paid through monthly payments under the project's long-term maintenance agreement with Alstom Power. Lake took two planned outages in the second quarter to replace one of its gas turbines and a portion of the other with temporary engine components available under Lake's lease engine agreement with GE, which permits Lake to install replacement engines while the project's components are being repaired. The cost of the repairs to Lake's engines is expected to be covered under the services agreement with GE that provides for unplanned maintenance.

In the six-month period ended June 30, 2011, we incurred approximately $45.6 million in capital expenditures for the construction of our Piedmont biomass project. For the remainder of 2011, we expect to incur approximately $62.5 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million. The project is being funded with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation.

Off-Balance Sheet Arrangements

As of June 30, 2011, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

The Lake project's operating margin is exposed to changes in the market price of natural gas until the expiration of its PPA on July 31, 2013. 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.

We have executed a strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale by periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps at Lake and Auburndale, through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, these natural gas swap hedges were de-designated and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

In 2011, projected cash distributions at Auburndale would change by approximately $0.5 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. In 2011, 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 volumes at the project.

Coal prices used in the 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.

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The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of June 30, 2011 and August 10, 2011:

	2011	2012	2013
Portion of gas volumes currently hedged:			
Lake:			
Contracted			
Financially hedged	78%	90%	83%
Total	78%	90%	83%
Auburndale:			
Contracted	80%	0%	0%
Financially hedged	13%	32%	79%
Total	93%	32%	79%
Average price of financially hedged volumes (per Mmbtu)			
Lake	$ 6.52	$ 6.90	$ 6.63
Auburndale	$ 6.68	$ 6.51	$ 6.92

In October 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando project at a weighted average price of $5.76/Mmbtu and represent approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015.

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.

Foreign Currency Exchange Rate Risk

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominately in Canadian dollars. Since our inception, we have had an established hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of our dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of our Canadian dollar obligations. 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) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts.

The foreign exchange forward contracts are recorded at fair value based on quoted market prices and the estimation of our credit rating or the credit rating of our counterparties. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

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The following table contains the components of recorded foreign exchange (gain) loss for the three and six-month periods ended June 30, 2011 and 2010:

	Three months ended June 30,		Six months ended June 30,	
	2011	**2010**	**2011**	**2010**
Unrealized foreign exchange (gain) loss:				
Convertible debentures	$ 1,317	$ (6,486)	$ 6,632	$ (2,505)
Forward contracts and other	1,303	12,309	(2,133)	7,704
	2,620	5,823	4,499	5,199
Realized foreign exchange gains on forward contract settlements	(3,155)	(1,599)	(5,692)	(2,767)
	$ (535)	$ 4,224	$ (1,193)	$ 2,432

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of June 30, 2011:

Convertible debentures, at carrying value	$ 20,970
Foreign currency forward contracts	$ (20,548)

On July 27, 2011, August 3, 2011 and August 5, 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to economically hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction.

The July 27, 2011 transactions include a forward purchase of $32.0 million at $0.9460 per Cdn$1.00, a call option to purchase $84.7 million at $0.94565 per Cdn$1.00 and a put option to sell $116.7 million at $0.90 per Cdn$1.00. The August 3, 2011 transactions include a forward purchase of $76.0 million at $0.9665 per Cdn$1.00, a call option to purchase $14.5 million at $0.9665 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00. The August 5, 2011 transactions include a forward purchase of $81.2 million at $0.9872 per Cdn$1.00, a call option to purchase $9.3 million at $0.9872 per Cdn$1.00 and a put option to sell $90.5 million at $0.90 per Cdn$1.00.

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 89% 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 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 $0.7 million.

ITEM 4. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness 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 evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report on Form 10-Q.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) under the Exchange Act) that occurred during the period covered by this report that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations over Internal Controls

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. However, internal controls over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Our Lake project is currently involved in a dispute with Progress Energy Florida 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 Progress. 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. Progress 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.

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 June 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

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"), 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, 2010.

ITEM 6. EXHIBITS

Exhibit Number	Description
2.1	Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services LTD., CPI Investments Inc. and Atlantic Power Corporation (incorporated by reference to the Current Report on Form 8-K filed on June 24, 2011).
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.

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SIGNATURES

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

Date: August 12, 2011	Atlantic Power Corporation		
	By:	/s/ LISA J. DONAHUE	
		Name:	Lisa J. Donahue
		Title:	*Interim Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*