ATLANTIC POWER CORP
Form 10-Q
August 09, 2010

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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, 2010

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 o No ý

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 o 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 9, 2010 was 60,510,070.

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ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND SIX MONTHS ENDED JUNE 30, 2010

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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.

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:

- expected opportunities for accretive acquisitions;
- the amount of distributions expected to be received from the projects for the full year 2010;
- estimated net cash tax refund in 2010;
- our forecast of expected after-tax cash flows from Idaho Wind for each full year of operations;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012; and
- the expected resumption of distributions from our Chambers, Selkirk and Delta projects in 2011.

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 Securities and Exchange Commission. 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;

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- increased competition, including for acquisitions; and

- our limited control over the operation of certain minority-owned projects.

Other factors, such as general economic conditions, including exchange rate fluctuations, also may have an effect on the results of our operations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf. For a description of risks that could cause our actual results to materially differ from our current expectations, please see "Risk Factors" included in the filings we make from time to time with the Securities and Exchange Commission.

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.

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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, 2010 (unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 63,314	$ 49,850
Restricted cash	14,579	14,859
Accounts receivable	18,433	17,480
Current portion of derivative instruments asset (Notes 7 and 8)	4,251	5,619
Prepayments, supplies, and other	4,019	3,019
Deferred income taxes	15,106	17,887
Refundable income taxes	10,588	10,552
Total current assets	130,290	119,266
Property, plant, and equipment, net (Note 5)	189,916	193,822
Transmission system rights (Note 5)	192,059	195,984
Equity investments in unconsolidated affiliates	259,443	259,230
Other intangible assets, net (Note 5)	64,810	71,770
Goodwill (Note 4)	12,453	8,918
Derivative instruments asset (Notes 7 and 8)	7,952	14,289
Other assets	5,602	6,297
Total assets	$ 862,525	$ 869,576
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 18,513	$ 21,661
Revolving credit facility	20,000	
Current portion of long-term debt (Note 6)	18,330	18,280
Current portion of derivative instruments liability (Notes 7 and 8)	5,108	6,512
Interest payable on convertible debentures	3,332	800
Dividends payable	5,184	5,242
Other current liabilities	10	752
Total current liabilities	70,477	53,247
Long-term debt (Note 6)	214,527	224,081
Convertible debentures	137,376	139,153
Derivative instruments liability (Notes 7 and 8)	17,011	5,513
Deferred income taxes	33,697	28,619
Other non-current liabilities	4,802	4,846
Shareholders' equity		

Common shares	544,647	541,917
Accumulated other comprehensive loss (Note 8)	(194)	(859)
Retained deficit	(163,299)	(126,941)
Noncontrolling interest (Note 4)	3,481	
Total shareholders' equity	384,635	414,117
Commitments and contingencies (Note 15)		
Subsequent events (Note 16)		
Total liabilities and shareholders' equity	$ 862,525	$ 869,576

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, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Project revenue:				
Energy sales	$ 16,659	$ 14,090	$ 32,572	$ 30,015
Energy capacity revenue	23,195	22,112	46,389	44,224
Transmission services	7,729	7,708	15,373	15,416
Other	321	360	791	649
	47,904	44,270	95,125	90,304
Project expenses:				
Fuel	15,771	12,627	31,928	27,588
Operations and maintenance	5,459	4,712	10,500	9,650
Project operator fees and expenses	983	758	1,902	2,031
Depreciation and amortization	10,071	10,588	20,142	21,254
	32,284	28,685	64,472	60,523
Project other income (expense):				
Change in fair value of derivative instruments (Notes 7 and 8)	992	469	(11,202)	360
Equity in earnings of unconsolidated affiliates	3,026	(982)	8,462	3,969
Interest expense, net	(4,308)	(4,816)	(8,719)	(9,320)
Other income, net	211	1,205	211	1,205
	(79)	(4,124)	(11,248)	(3,786)
Project income	15,541	11,461	19,405	25,995
Administrative and other expenses (income):				
Management fees and administration	3,843	3,105	7,943	5,484
Interest, net	2,518	10,553	5,312	20,170
Foreign exchange loss (Note 8)	4,224	12,929	2,432	9,506
Other income, net	(26)	(14)	(26)	(30)
	10,559	26,573	15,661	35,130
Income (loss) from operations before income taxes	4,982	(15,112)	3,744	(9,135)
Income tax expense (benefit) (Note 9)	3,618	(4,383)	8,491	(2,649)
Net income (loss)	1,364	(10,729)	(4,747)	(6,486)
Net loss attributable to noncontrolling interest	(81)		(129)	
Net income (loss) attributable to Atlantic Power Corporation	$ 1,445	$ (10,729)	$ (4,618)	$ (6,486)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 11)				
Basic	$ 0.02	$ (0.18)	$ (0.08)	$ (0.11)
Diluted	$ 0.04	$ (0.18)	$ (0.08)	$ (0.11)

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, 2010	Six months ended June 30, 2009
Cash flows from operating activities:		
Net loss	$ (4,747)	$ (6,486)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	20,142	21,254
Loss on sale of property, plant and equipment		333
Gain on step-up valuation of Rollcast acquisition	(211)	
Earnings from unconsolidated affiliates	(8,462)	(3,969)
Distributions from unconsolidated affiliates	5,718	13,021
Unrealized foreign exchange loss	5,199	9,630
Change in fair value of derivative instruments	11,202	(360)
Change in deferred income taxes	7,416	564
Change in other operating balances		
Accounts receivable	(953)	7,880
Prepayments, refundable income taxes and other assets	(481)	(5,859)
Accounts payable and accrued liabilities	(956)	(5,767)
Other liabilities	2,111	283
Cash provided by operating activites	35,978	30,524
Cash flows used in investing activities:		
Acquisitions and investments, net of cash acquired	324	(3,000)
Change in restricted cash (Note 1)	280	347
Biomass development costs	(948)	
Proceeds from sale of property, plant and equipment		167
Purchase of property, plant and equipment	(1,520)	(933)
Cash used in investing activities	(1,864)	(3,419)
Cash flows used in financing activities:		
Shares acquired in normal course issuer bid (Note 14)		(3,369)
Proceeds from revolving credit facility borrowings	20,000	
Equity investment from noncontrolling interest	200	
Dividends paid	(31,709)	(11,672)
Repayment of project-level debt	(9,141)	(6,414)
Cash used in financing activities	(20,650)	(21,455)
Increase in cash and cash equivalents	13,464	5,650
Cash and cash equivalents at beginning of period	49,850	37,327
Cash and cash equivalents at end of period	$ 63,314	$ 42,977
Supplemental cash flow information		
Interest paid	$ 11,437	$ 29,162
Income taxes paid (refunded), net	$ 1,045	$ 651

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of presentation

Overview

Atlantic Power Corporation ("Atlantic Power") is a corporation established under the laws of the Province of Ontario on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. We issued income participating securities ("IPSs") for cash pursuant to an initial public offering on the Toronto Stock Exchange, or the TSX, on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. On November 27, 2009 our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange, or the NYSE, under the symbol "AT" on July 23, 2010.

Our current portfolio consists of interests in 12 operational power generation projects across eight states, one wind project under construction in Idaho, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW"), in which our ownership interest is approximately 808 MW.Four of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P. and Atlantic Path 15, LLC. The interim consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("GAAP") with a reconciliation to Canadian GAAP in Note 17. The Canadian securities legislation allow issuers that are required to file reports with the Securities and Exchange Commission ("SEC") in the United States to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. Prior to 2010, we prepared our consolidated financial statements in accordance with Canadian GAAP.

The interim consolidated financial statements do not contain all the disclosures required by United States and Canadian GAAP. The interim consolidated financial statements have been prepared in accordance with the SEC's regulations for interim financial information and with the instructions to Form 10-Q. The accounting policies we follow are set forth below in Note 2, *Summary of significant accounting policies.* The interim consolidated financial statements follow the same accounting principles and methods of application as the most recent annual consolidated financial statements as there are no material differences in our accounting policies between United States and Canadian GAAP at June 30, 2010 other than as denoted in Note 17. Interim results are not necessarily indicative of results for a 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, 2010, the results of operations for the three and six month periods ended June 30, 2010 and 2009, and our cash flows for the six month periods ended June 30, 2010 and 2009.

Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows have been reported as an investing activity to reflect the use of the restricted cash in the current period. In previous periods, changes in restricted cash were reported as cash flows from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of presentation (Continued)

statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

2. Summary of significant accounting policies

(a) Basis of consolidation and accounting:

The accompanying interim consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

As such, we apply the standard that requires consolidation of variable interest entities ("VIEs"), for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party will absorb a majority of the expected losses of the VIE, receive the majority of the expected residual returns of the VIE, or both. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we record all of our investments that we do not financially control under the equity method of accounting.

We eliminate all intercompany accounts and transactions in consolidation.

(b) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(c) Revenue:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the power purchase agreements ("PPAs") are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

Commission ("FERC") and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different than the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

(d) Use of fair value:

We utilize a fair value hierarchy that gives the highest priority to quoted prices in active markets and is applicable to fair value measurements of derivative contracts and other instruments that are subject to mark-to-market accounting. Refer to Note 7 for more information.

(e) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations.

The following table summarizes derivative financial instruments that are not designated as hedges and the accounting treatment in the consolidated statements of operations of the changes in fair value of such derivative financial instrument:

Derivative financial instrument	Classification of changes in fair value
Foreign currency forward contracts	Foreign exchange loss (gain)
Lake natural gas swaps	Change in fair value of derivative instruments
Auburndale natural gas swaps	Change in fair value of derivative instruments
Interest rate swap	Change in fair value of derivative instruments

Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Unrealized gains or losses on the interest rate swap designated as a hedge are deferred and recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(f) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. As major maintenance occurs and parts are replaced on the plant's combustion and steam turbines, maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(g) Transmission system rights:

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California. Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of Path 15.

(h) Impairment of long-lived assets, non-amortizing intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(i) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects.

Power purchase agreements are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

(j) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 9 for more information.

(k) Foreign currency translation:

Our functional currency and reporting currency is the United States dollar. The functional currency of our subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the period. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates.

(l) Long-term incentive plan:

The officers and other employees of Atlantic Power are eligible to participate in the Long-Term Incentive Plan ("LTIP") that was implemented in 2007. In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under the LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(m) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivatives and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative contracts. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to payment history. See Note 12, *Segment and related information*, for a further discussion of customer concentrations.

(n) Segments:

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets. Each of our projects is an operating segment. Based on similar economic and other characteristics, we aggregate several of the projects into the Other Project Assets reportable segment.

3. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss), net of tax of $120 and $1,081, respectively, for the three months ended June 30, 2010 and 2009, and net of tax of $109 and $(1,393), respectively, for the six months ended June 30, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Net income (loss)	$ 1,364	$ (10,729)	$ (4,747)	$ (6,486)
Unrealized gain (loss) on hedging activity	180	1,622	164	(2,089)
Comprehensive income (loss)	$ 1,544	$ (9,107)	$ (4,583)	$ (8,575)

4. Acquisitions

Rollcast

On March 31, 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina Corporation for $3.0 million in cash. On March 1, 2010, we paid $1.2 million in cash for an additional 15% of the shares of Rollcast, increasing our interest from 40% to 55% and providing us control of Rollcast. We consolidated Rollcast as of this date. We previously accounted for our 40% interest in Rollcast as an equity method investment. On April 28, 2010, we paid an additional $0.8 million to increase our ownership interest in Rollcast to 60%.

Rollcast is a developer of biomass power plants in the southeastern U.S. with five, 50 MW projects in various stages of development. The investment in Rollcast gives us the option but not the obligation to invest equity in Rollcast's biomass power plants.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Acquisitions (Continued)

The following table summarizes the consideration transferred to acquire Rollcast and the preliminary estimated amounts of identifiable assets acquired and liabilities assumed at the acquisition date, as well as the fair value of the non-controlling interest in Rollcast at the acquisition date:

Fair value of consideration transferred:	
Cash	$ 1,200
Other items to be allocated to identifiable assets acquired and liabilities assumed:	
Fair value of our investment in Rollcast at the acquisition date	2,758
Fair value of noncontrolling interest in Rollcast	3,410
Gain recognized on the step acquisition	211
Total	$ 7,579
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Cash	$ 1,524
Property, plant and equipment	130
Prepaid expenses and other assets	133
Capitalized development costs	2,705
Trade and other payables	(448)
Total identifiable net assets	4,044
Goodwill	3,535
	$ 7,579

As a result of obtaining control over Rollcast, our previously held 40% interest was remeasured to fair value, resulting in a gain of $0.2 million. This has been recognized in other income (expense) in the consolidated statements of operations.

The fair value of the noncontrolling interest of $3.4 million in Rollcast was estimated by applying an income approach using the discounted cash flow method. This fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 fair value measurement. The fair value estimate utilized an assumed discount rate of 9.4% which is composed of a risk-free rate and an equity risk premium determined by the capital asset pricing of companies deemed to be similar to Rollcast. The estimate assumed that no fair value adjustments are required because of the lack of control or lack of marketability that market participants would consider when estimating the fair value of the noncontrolling interest in Rollcast.

The goodwill is attributable to the value of future biomass power plant development opportunities. It is not expected to be deductible for tax purposes. All of the $3.5 million of goodwill was assigned to the Other Project Assets segment.

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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, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
Property, plant and equipment	$ 80,154	$ 74,567
Transmission system rights	39,611	35,685
Other intangible assets	55,800	45,368

6. Long-term debt

Long-term debt represents our consolidated share of project long-term debt 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 debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	June 30, 2010	December 31, 2009
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 221,190	$ 230,331
Purchase accounting fair value adjustments	11,667	12,030
Less: current portion of long-term debt	(18,330)	(18,280)
Long-term debt	$ 214,527	$ 224,081

Project-level debt is secured by the respective projects and their contracts with no other recourse to us. At June 30, 2010, all of our projects were in compliance with the covenants contained in project-level debt.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Fair value of financial instruments

The following represents the fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of June 30, 2010 and December 31, 2009. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 63,314	$	$	$ 63,314
Restricted cash	14,579			14,579
Derivative instruments asset		12,203		12,203
Total	$ 77,893	$ 12,203	$	$ 90,096
Liabilities:				
Derivative instruments liability	$	$ 22,119	$	$ 22,119
Total	$	$ 22,119	$	$ 22,119

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 49,850	$	$	$ 49,850
Restricted cash	14,859			14,859
Derivative instruments asset		19,908		19,908
Total	$ 64,709	$ 19,908	$	$ 84,617
Liabilities:				
Derivative instruments liability		12,025		12,025
Total	$	$ 12,025	$	$ 12,025

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, 2010, the credit reserve resulted in a $1.3 million net increase in fair value, which is comprised of a $0.3 million gain in other comprehensive income and a $1.1 million gain in change in fair value of derivative instruments offset by a $0.1 million loss in foreign exchange.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

We have elected to disclose derivative instruments 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, 2010	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap contract current	$	$ 479
Interest rate swap contract long-term		141
Total derivative instruments designated as cash flow hedges		620
Derivative instruments not designated as cash flow hedges:		
Interest rate swap contract current		1,190
Interest rate swap contract long-term		2,387
Foreign currency forward contracts current	4,251	
Foreign currency forward contracts long-term	7,952	
Natural gas swap contracts current		3,439
Natural gas swap contracts long-term		14,483
Total derivative instruments not designated as cash flow hedges	12,203	21,499
Total derivative instruments	$ 12,203	$ 22,119

	December 31, 2009	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap contract current	$	$ 726
Interest rate swap contract long-term		167
Total derivative instruments designated as cash flow hedges		893
Derivative instruments not designated as cash flow hedges:		
Interest rate swap contract current		1,705
Interest rate swap contract long-term		1,707
Foreign currency forward contracts current	5,619	
Foreign currency forward contracts long-term	14,289	
Natural gas swap contracts current	95	4,174
Natural gas swap contracts long-term	14	3,655

Total derivative instruments not designated as cash flow hedges		20,017		11,241
Total derivative instruments	$	20,017	$	12,134

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Natural gas swaps

The Lake project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its natural gas supply contract on June 30, 2009 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 expiry of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

Our strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale consists of 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 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, we de-designated these natural gas swap hedges and the changes in their fair value subsequent to July 1, 2009 are now recorded in change in fair value of derivative instruments in the consolidated statements of operations. Amounts in accumulated other comprehensive income (loss) remaining prior to de-designation are amortized into the consolidated statements of operations over the remaining lives of the natural gas swaps.

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. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

The interest rate swap is a derivative financial instrument designated as a cash flow hedge. The instrument is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in accumulated other comprehensive income (loss).

Impact of derivative instruments on the consolidated income statements

Unrealized gains on interest rate swaps designated as cash flow hedges have been recorded in the consolidated statements of operations as a gain in other comprehensive income of $0.3 million for each of the three and six month periods ended June 30, 2010. Realized losses on these interest rate swaps of $0.2 million and $0.4 million were recorded in interest expense, net for the three and six month periods ended June 30, 2010.

Unrealized gains and losses on natural gas swaps designated as cash flow hedges are recorded in other comprehensive income in the consolidated statements of operations. In the period in which the unrealized gains and losses are settled, the cash settlement payments are recorded as fuel expense. Other comprehensive loss recorded for natural gas swap contracts accounted for as cash flow hedges totaled $5.1 million, net of tax, prior to July 1, 2009 when hedge accounting for these natural gas swaps

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

was discontinued prospectively. Amortization of the loss of $0.4 million and $0.8 million was recorded in change in fair value of derivative instruments for the three and six month periods ended June 30, 2010.

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 derivatives not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended June 30, 2010	Six months ended June 30, 2010
Natural gas swaps	Fuel	$ 2,621	$ 4,439
Foreign currency forwards	Foreign exchange gain	(1,599)	(2,767)
Interest rate swaps	Interest, net	474	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 changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Change in fair value of derivative instruments:				
Interest rate swaps	$ (120)	$ 469	$ (166)	$ 360
Natural gas swaps	1,112		(11,036)	
	$ 992	$ 469	$ (11,202)	$ 360

Notional volumes of derivative transactions

The following table summarizes the net notional volume of our derivative transactions by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of June 30, 2010:

	Units	Notional amount as of June 30, 2010
Interest rate swaps	US$	$ 10,219
Currency forwards	Cdn$	$ 257,700
Natural gas swaps	Mmbtu	15,900

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Foreign currency forward contracts

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 predominantly in Canadian dollars. We have a hedging strategy for the purpose of reinforcing 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 of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly dividend payments at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on our 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), through December 2013.

In addition, we have executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on our 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"). The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a 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 estimated 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 at June 30, 2010 is an asset of $12.2 million. 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, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Unrealized foreign exchange (gain) loss:				
Subordinated notes and convertible debentures	$ (6,486)	$ 30,401	$ (2,505)	$ 17,635
Forward contracts and other	12,309	(16,792)	7,704	(8,005)
	5,823	13,609	5,199	9,630
Realized foreign exchange gains on forward contract settlements	(1,599)	(680)	(2,767)	(124)
	$ 4,224	$ 12,929	$ 2,432	$ 9,506

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, 2010:

Convertible debentures	$ 13,738
Foreign currency forward contracts	26,133

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. 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 a 40% effective tax rate:

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, 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)

9. Income taxes

The difference between the actual tax expense of $3.6 million and $8.5 million for the three and six months ended June 30, 2010, respectively, and the expected income tax expense, based on a combined Federal and State tax rate of 40%, of $2.0 million and $1.5 million, respectively, is primarily due to an increase in the valuation allowance and various other permanent differences.

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Current income tax expense (benefit)	$ 1,038	$ (1,743)	$ 1,075	$ (3,213)
Deferred tax expense (benefit)	2,580	(2,640)	7,416	564
Total income tax expense (benefit)	$ 3,618	$ (4,383)	$ 8,491	$ (2,649)

Valuation Allowance

As of June 30, 2010, we have recorded a valuation allowance of $69.1 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.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Long-Term Incentive Plan

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2010:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2009	471,281	$ 7.30
Granted	305,112	$ 12.16
Additional shares from dividends	27,489	$ 8.94
Vested	(222,266)	$ 3.13
Outstanding at June 30, 2010	581,616	$ 9.68

In the second quarter of 2010, the Board of Directors approved an amendment to the LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return ("TSR") of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Vested notional units will be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Notional units granted prior to the 2010 performance period are subject to the vesting conditions of the LTIP before the amendments made in 2010. We reclassified the portion of outstanding awards expected to vest in common shares totaling $1.4 million from accounts payable and accrued liabilities and other non-current liabilities to common shares as of the date the LTIP was modified. The amended LTIP was approved by our shareholders on June 29, 2010.

On March 29, 2010, our board of directors approved the grant of 138,892 notional LTIP units for the 2009 performance period under the terms of the LTIP before the 2010 amendments. In May 2010, our board of directors approved the initial grant of 83,110 notional LTIP units for executive officers under the amended LTIP for the 2010-2012 performance period, subject to final shareholder approval of the amended LTIP, which occurred on June 29, 2010. Also in May 2010 and subject to the final shareholder approval of the amended LTIP, our board of directors granted transition awards to our executive officers consisting of an additional 83,110 notional LTIP units. The transition awards are designed to mitigate the impact of the changes in vesting provisions of the LTIP from a ratable vesting over three years to cliff vesting at the end of three years. The transition awards are subject to the performance measurement and other provisions of the amended LTIP, except that $^{1}/_{3}$ of the transition awards vest in March 2011 and the other $^{2}/_{3}$ vest in March 2012.

The notional units, other than the transition awards, granted under the amended LTIP cliff-vest three years after the grant date. The final number of notional units that will vest, if any, at the end of the three year vesting period will be based on the Company's achievement of target levels of relative TSR, which is the change in the value of an investment in the Company's common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Long-Term Incentive Plan (Continued)

period. The total number of notional units vesting could equal up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of target levels of TSR during the measurement period.

For new awards granted under the amended LTIP, we record compensation expense ratably from the grant date through the end of the performance period based on the grant date fair value. Compensation expense is recognized regardless of whether the TSR market condition is satisfied, provided that the LTIP participant remains employed by the Company. The fair value of the outstanding notional units at June 30, 2010, $2.0 million, is based upon a Monte Carlo simulation model, which encompasses estimated TSR during the performance period compared to the estimated TSR of the peer companies.

In calculating the fair value of the award, the Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the probability of satisfying the TSR market condition stipulated in the award. The Monte Carlo simulation model computed simulated TSR for the Company and for its peer companies during the remaining time in the performance period with the following inputs: (i) stock price on the measurement date (ii) expected volatility; (iii) risk-free interest rate; (iv) dividend yield and (v) correlations of historical common stock returns between the Company and the peer companies and among the peer companies. Expected volatilities utilized in the Monte Carlo model are based on historical volatility of the Company's and the peer companies' stock prices over a period equal in length to that of the remaining vesting period. The risk-free interest rate is derived from the U.S. Treasury yield curve in effect at the time of grant with a term equal to the performance period assumption at the time of grant.

The calculation of simulated TSR under the Monte Carlo model for the remaining time in the performance period included the following assumptions:

	Six months ended June 30, 2010
Weighted average risk free rate of return	0.9%
Dividend yield	9.4%
Expected volatility Company	45%
Expected volatility peer companies	30 - 60%
Weighted average remaining measurement period	1.8 years

11. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2009. 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 month period ended June 30, 2010 and the three and six month periods ended June 30, 2009, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table sets forth the weighted average number of shares outstanding and potentially dilutive shares utilized in per share calculations for the three and six month periods ended June 30, 2010 and 2009:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Basic shares outstanding	60,481	60,600	60,443	60,769
Dilutive potential shares:				
Convertible debentures	11,473	4,839	11,473	4,839
LTIP notional units	409	539	402	425
Potentially dilutive shares	72,363	65,978	72,318	66,033

12. 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 less 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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

contracts that are 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, 2010:								
Operating revenues	$ 7,729	$ 19,570	$ 17,842	$ 2,763	$	$	$	$ 47,904
Segment assets	213,275	120,929	115,822	40,620		8,322	363,557	862,525
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 7,062	$ 10,431	$ 7,299	$ 1,002	$ 4,141	$ 8,591	$	$ 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 gain							4,224	4,224
Other income, net							(26)	(26)
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 loss	$ 881	$ 4,469	$ 6,745	$ 256	$ 1,654	$ 546	$ (13,187)	$ 1,364

	Path 15	Auburndale	Lake	Pasco	Chambers	Project Assets	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2009:								
Operating revenues	$ 7,708	$ 18,263	$ 15,239	$ 3,060	$	$	$	$ 44,270
Segment assets	225,167	144,228	125,381	44,671		3,215	331,261	873,923
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 6,931	$ 10,386	$ 7,723	$ 901	$ (1,128)	$ 9,172	$	$ 33,985
Change in fair value of derivative instruments					(1,010)	(1,311)		(2,321)
Depreciation and amortization	2,115	4,949	2,777	747	844	5,990		17,422
Interest, net	3,221	693		3	2,015	2,555		8,487
Other project (income) expense	(1,229)		61	(25)	207	(78)		(1,064)
Project income	2,824	4,744	4,885	176	(3,184)	2,016		11,461
Interest, net							10,553	10,553
Administration							3,105	3,105
Foreign exchange gain							12,929	12,929
Other income, net							(14)	(14)
Loss from operations before income taxes	2,824	4,744	4,885	176	(3,184)	2,016	(26,573)	(15,112)
Income tax expense (benefit)							(4,383)	(4,383)

Net loss	$	2,824	$	4,744	$	4,885	$	176	$	(3,184)	$	2,016	$	(22,190)	$	(10,729)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

	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	$	$	$	$ 95,125
Segment assets	213,275	120,929	115,822	40,620		8,322	363,557	862,525
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 14,115	$ 19,802	$ 14,612	$ 2,417	$ 10,129	$ 16,200	$	$ 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 income, net							(26)	(26)
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 loss	$ 1,940	$ 4,209	$ 3,856	$ 925	$ 5,103	$ 1,633	$ (22,413)	$ (4,747)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2009:								
Operating revenues	$ 15,416	$ 37,989	$ 31,104	$ 5,795	$	$	$	$ 90,304
Segment assets	225,167	144,228	125,381	44,671		3,215	331,261	873,923
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 13,833	$ 18,547	$ 15,621	$ 2,869	$ 5,024	$ 19,161	$	$ 75,055
Change in fair value of derivative instruments					(1,524)	935		(589)
Depreciation and amortization	4,311	9,882	5,566	1,494	1,687	12,065		35,005
Interest, net	6,444	1,314	(6)	(43)	4,029	3,875		15,613
Other project (income) expense	(1,229)		62	(25)	410	(187)		(969)
Project income	4,307	7,351	9,999	1,443	422	2,473		25,995
Interest, net							20,170	20,170
Administration							5,484	5,484
Foreign exchange gain							9,506	9,506
Other income, net							(30)	(30)
Loss from operations before income taxes	4,307	7,351	9,999	1,443	422	2,473	(35,130)	(9,135)
Income tax expense (benefit)							(2,649)	(2,649)
Net loss	$ 4,307	$ 7,351	$ 9,999	$ 1,443	$ 422	$ 2,473	$ (32,481)	$ (6,486)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Segment and related information (Continued)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 77% and 16%, respectively, of total consolidated revenues for the three months ended June 30, 2010 and 75% and 17% for the three months ended June 30, 2009 and 77% and 16%, respectively, of total consolidated revenues for the six months ended June 30, 2010 and 76% and 17% for the six months ended June 30, 2009. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

13. Related party transactions

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 Capital Partners, LLC ("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 million, to be satisfied by a payment of $6 million that was made at the termination date, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We recorded the remaining liability associated with the termination fee at its estimated fair value of $8.1 million at December 31, 2009. The contract termination liability is being accreted to the final amounts due over the term of these payments.

14. Normal course issuer bid

In 2008, we initiated a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of Atlantic Power's public float at that time. For the six months ended June 30, 2009, we acquired 481,600 IPSs at an average price of Cdn$8.42 under the terms of our existing normal course issuer bid. As of June 30, 2009, we had acquired a cumulative total of 1,040,220 IPSs at an average price of Cdn$8.61 since the inception of the issuer bid in July 2008. We paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

15. Commitments and contingencies

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, 2010 which are expected to have a material impact on our financial position or results of operations.

16. Subsequent events

These financial statements and notes reflect our evaluation of events occurring subsequent to the balance sheet date through August 9, 2010, the date the interim consolidated financial statements were issued.

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("IWP") for approximately $40 million. IWP recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is expected to be completed in late 2010 or early 2011. IWP has 20-year PPAs with Idaho Power Company. Our investment in IWP was funded with cash on hand and a

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

16. Subsequent events (Continued)

$20 million borrowing under our senior credit facility. Idaho Wind will be accounted for under the equity method of accounting.

17. United States and Canadian accounting policy differences

In accordance with Canadian securities legislation, issuers that file reports with the Securities and Exchange Commission in the United States are allowed to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. We have included a reconciliation highlighting the material differences between our consolidated financial statements prepared in accordance with United States GAAP compared to its consolidated financial statements prepared in accordance with Canadian GAAP below.

Consolidated reconciliation of net income and shareholders' equity

Net income (loss) and shareholders' equity reconciled to Canadian GAAP are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Net income (loss), based on United States GAAP	$ 1,364	$ (10,729)	$ (4,747)	$ (6,486)
Changes in fair value of power purchase agreement, net of tax(1)	(4,593)	27,600	(16,892)	(10,126)
Projects accounted for under the cost method of accounting, net of tax(2)	1,744	2,733	1,822	4,012
Net income (loss), based on Canadian GAAP	$ (1,485)	$ 19,604	$ (19,817)	$ (12,600)

	June 30,	
	2010	2009
Shareholders' equity, based on United States GAAP	$ 384,635	$ 130,510
Adjusted for cumulative effect of US/Canadian differences	70,312	51,844
	454,947	182,354
Net earnings for the period, Canadian GAAP	(19,817)	(12,600)
Shareholders' equity, based on Canadian GAAP	$ 435,130	$ 169,754

(1) The accounting standard for derivative instruments provides an exemption for PPAs that contain both a capacity payment and an energy component which, if certain criteria are met, qualifies the PPA for the normal purchases and normal sales treatment. A similar exemption does not exist under Canadian GAAP and accordingly, a PPA with a capacity payment, a minimum or specified quantity of energy and delivery into a liquid market is subject to fair value accounting. Our PPA at the Chambers project meets the normal purchases and normal sales exemption under United States GAAP and is not subject to fair value accounting.

(2) We follow a standard under United States GAAP that establishes a presumption of significant influence with a low threshold of ownership in investments in limited partnerships and requires accounting under the equity method. Our investments in the Selkirk and Gregory projects are

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. United States and Canadian accounting policy differences (Continued)

accounted for under the cost method for Canadian GAAP because there is not a different threshold for ownership interest in limited partnerships and we do not exercise significant influence over the operating and financial policies of these investments.

Earnings per share

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Earnings per share under Canadian GAAP				
Basic	$ (0.02)	$ 0.32	$ (0.33)	$ (0.21)
Diluted	$ (0.02)	$ 0.30	$ (0.33)	$ (0.21)

Condensed consolidated balance sheet

	June 30, 2010 (Canadian GAAP)	December 31, 2009 (Canadian GAAP)
Assets		
Current assets	$ 151,215	$ 149,340
Equity investments in unconsolidated affiliates(1)	57,877	61,037
Other long-term assets	782,865	827,175
Total assets	$ 991,957	$ 1,037,552
Liabilities and Shareholders' Equity		
Current liabilities	$ 93,055	$ 77,471
Other non-current liabilities	463,772	480,398
Shareholders' equity:		
Common shares	544,034	541,304
Accumulated other comprehensive loss	(194)	(859)
Retained deficit	(112,191)	(60,762)
Noncontrolling interest	3,481	
Total shareholders' equity	435,130	479,683
Total liabilities and shareholders' equity	$ 991,957	$ 1,037,552

(1) We follow a standard under United States GAAP that requires the equity method of accounting for our investments with 50% or less ownership interest in which we do not have a controlling interest. Under Canadian GAAP, our share of each of the assets, liabilities, revenues and expenses of our investments that are subject to joint control is proportionately consolidated.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. United States and Canadian accounting policy differences (Continued)

Condensed consolidated statement of operations

	Three months ended June 30, 2010 (Canadian GAAP)	Three months ended June 30, 2009 (Canadian GAAP)	Six months ended June 30, 2010 (Canadian GAAP)	Six months ended June 30, 2009 (Canadian GAAP)
Project Income				
Project revenue	$ 75,912	$ 73,242	$ 153,539	$ 156,792
Project expenses	56,245	60,214	113,477	123,492
Project other expenses	(12,321)	46,311	(55,456)	(20,289)
	7,346	59,339	(15,394)	13,011
Administration and other expenses, net	10,560	26,117	15,662	34,671
Loss from operations before income taxes	(3,214)	33,222	(31,056)	(21,660)
Income tax expense (benefit)	(1,729)	13,618	(11,239)	(9,060)
Net income (loss)	(1,485)	19,604	(19,817)	(12,600)
Less: Net loss attributable to noncontrolling interest	(81)		(129)	
Net income (loss) attributable to Atlantic Power Corporation	$ (1,404)	$ 19,604	$ (19,688)	$ (12,600)

Condensed consolidated statement of cash flows

	Three months ended June 30, 2010 (Canadian GAAP)	Three months ended June 30, 2009 (Canadian GAAP)	Six months ended June 30, 2010 (Canadian GAAP)	Six months ended June 30, 2009 (Canadian GAAP)
Cash provided by operating activities	$ 17,398	$ 10,100	$ 40,976	$ 31,722
Cash used in investing activities	6,811	11,113	(2,380)	656
Cash used in financing activities	(5,116)	(17,243)	(26,374)	(26,756)
Increase in cash and cash equivalents	19,093	3,970	12,222	5,622
Cash and cash equivalents, beginning of period	47,632	44,218	54,503	42,566
Cash and cash equivalents, end of period	$ 66,725	$ 48,188	$ 66,725	$ 48,188

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

The following discussion of the financial condition and results of operations of Atlantic Power 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 is an independent power producer, with power projects located in major markets in the United States. Our current portfolio consists of interests in 12 operational power generation projects across eight states, one wind project under construction in Idaho, a 500 kilovolt 84-mile electric transmission line located in California, and six development projects in five states. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,823 megawatts (or "MW"), in which our ownership interest is approximately 808 MW. We sell the capacity and energy from our projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2010 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 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 most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power industry to operate and maintain our projects, including Caithness Energy, LLC and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Atlantic Power Corporation is organized under the laws of the Province of British Columbia. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our website is atlanticpower.com. Information contained on our website is not part of this Quarterly Report on Form 10-Q.

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

As of August 9, 2010, we had 60,510,070 common shares, Cdn$60 million principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), and Cdn$86.25 million principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures" and together with 2006 Debentures, the "Debentures") outstanding. The 2006 Debentures and the 2009 Debentures are convertible at any time, at the option of the holder, into 80.645 and 76.923 common shares per Cdn$1,000 principal amount of Debentures, respectively, representing a conversion price of Cdn$12.40 and Cdn$13.00, respectively, per common share. Holders of common shares receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

On November 24, 2009, our shareholders approved our conversion from the previous Income Participating Security ("IPS") structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form part of an IPS was exchanged for approximately 0.44 of a new common share. This transaction resulted in the

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extinguishment of Cdn$347,832 principal value of 11% Subordinated Notes due 2016 that previously formed a part of each IPS.

OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of August 9 2010, including its interest in each facility. Management believes the portfolio is well diversified based on 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]	Accounting Treatment[2]	Net MW[3]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	E	89	ACE[4]	2024	BBB+
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via CAISO[5]	N/A[6]	BBB+ to A[7]
Orlando	Florida	Natural Gas	129	50.00%	E	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013[8]	A[9]
Selkirk	New York	Natural Gas	345	18.50%[10]	E	15	Merchant	N/A	N/R
						49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	E	59	Fortis Energy Marketing and Trading	2013	A-

						9	Sherwin Alumina	2020	NR
Topsham[11]	Maine	Hydro	14	50.00%	E	7	Central Maine Power	2011	BBB+
Badger Creek	California	Natural Gas	46	50.00%	E	23	Pacific Gas & Electric	2011	BBB+
Rumford	Maine	Coal/Biomass	85	23.50%[10]	E	20	Rumford Paper Co.	2010	N/R
Koma Kulshan	Washington	Hydro	13	49.80%	E	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	PNM	2020	BB-
Idaho Wind[12]	Idaho	Wind	183	27.56%	E	51	Idaho Power Co.	2030	BBB

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

(2) Accounting Treatment: C Consolidated; and E Equity Method of Accounting

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

(4) Includes separate power sales agreement in which the Project and ACE share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(5) California utilities pay TACs to CAISO, who then pays owners of TSRs, such as Path 15, in accordance with its FERC approved annual revenue requirement.

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

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(7) Largest payers of TACs supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per CAISO imposed schedule.

(8) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.

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

(10) Represents our estimated share of the cash flow from the Project.

(11) The Company owns its interest in this Project as a lessor.

(12) Project currently under construction and is expected to be completed in late 2010 or early 2011.

Recent Developments

In March 2010, the Board of Directors approved an amendment to the LTIP and the amended plan was approved by the shareholders on June 29, 2010. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units granted will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

In April 2010, we filed an initial registration statement on Form 10 with the U.S. Securities and Exchange Commission. Our registration statement was declared effective on July 21, 2010 and we listed our common shares on the New York Stock Exchange on July 23, 2010. Beginning with the first quarter 2010, we have commenced reporting under U.S. GAAP. Amounts reported in previous periods under Canadian GAAP have been conformed to U.S. GAAP in this Quarterly Report on Form 10-Q.

In April 2010, we invested an additional $0.8 million in Rollcast to bring our total ownership interest to 60%. During the second quarter of 2010, Rollcast executed an engagement letter and term sheet with two banks to co-arrange debt financing and also entered into a construction agreement for its first 50 MW biomass project in Barnesville, Georgia.

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("IWP") for approximately $40 million. IWP recently commenced construction of a 183 MW wind power project located near Twin City, Idaho, which is expected to be completed in late 2010 or early 2011. IWP has 20-year PPAs with Idaho Power Company. Our investment in IWP was funded with cash on hand and a $20 million borrowing under our senior credit facility. Upon completion of construction, we expect Idaho Wind to provide after-tax cash flows to us of $4.5 million to $5.5 million for each full year of operations.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

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In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of deferred tax assets and the fair value of derivatives.

For a summary of our significant accounting policies, see Note 2 to our interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Impairment of long-lived assets and equity investments

Long-lived assets, which include property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. We also consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers or employ other valuation techniques. We use our best estimates in making these evaluations. However, actual results could vary from the assumptions used in our estimates and the impact of such variations could be material.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level, non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary.

When we determine that an impairment test is required, the future projected cash flows from the equity investment are the most significant factor in determining whether impairment exists and, if so, the amount of the impairment charges. We use our best estimates of market prices of power and fuel and our knowledge of the operations of the project and our related contracts when developing these cash flow estimates. In addition, when determining fair value using discounted cash flows, the discount rate used can have a material impact on the fair value determination. Discount rates are based on our risk of the cash flows in the estimate, including when applicable, the credit risk of the counterparty that is contractually obligated to purchase electricity or steam from the project.

We generally consider our investments in our equity method investees to be strategic long-term investments that comprise a significant portion of our core operating business. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than

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the carrying value and the decline in value is considered to be other than temporary, an appropriate write-down is recorded based on the excess of the carrying value over the best estimate of fair value of the investment. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates and the impact of such variations could be material.

Fair Value of Derivatives

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices, foreign currency and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives.

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair value measurements of these derivative assets and liabilities are based largely on quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis.

Derivative assets are discounted for credit risk using credit spreads representative of the counterparty's probability of default. For derivative liabilities, fair value measurement reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying credit spreads approximating our estimate of corporate credit rating against the respective derivative liability.

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

Income Taxes and Valuation Allowance for Deferred Tax Assets

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. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards.

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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, 2010 and 2009. 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, 2010	Three months ended June 30, 2009	Six months ended June 30, 2010	Six months ended June 30, 2009
Project revenue				
Auburndale	$ 19,570	$ 18,263	$ 40,037	$ 37,989
Lake	17,842	15,239	34,083	31,104
Pasco	2,763	3,060	5,632	5,795
Path 15	7,729	7,708	15,373	15,416
Chambers				
Other Project Assets				
	47,904	44,270	95,125	90,304
Project expenses				
Auburndale	14,089	12,826	30,133	29,324
Lake	12,810	10,293	24,007	21,049
Pasco	2,507	2,906	4,707	4,419
Path 15	2,762	2,892	5,452	5,894
Chambers				
Other Project Assets	116	(232)	173	(163)
	32,284	28,685	64,472	60,523
Project other income (expense)				
Auburndale	(1,012)	(693)	(5,695)	(1,314)
Lake	1,713	(61)	(6,220)	(56)
Pasco		22		67
Path 15	(3,096)	(1,992)	(6,242)	(5,215)
Chambers	1,654	(3,184)	5,103	422
Other Project Assets	662	1,784	1,806	2,310
	(79)	(4,124)	(11,248)	(3,786)
Total project income				
Auburndale	4,469	4,744	4,209	7,351
Lake	6,745	4,885	3,856	9,999
Pasco	256	176	925	1,443
Path 15	1,871	2,824	3,679	4,307
Chambers	1,654	(3,184)	5,103	422
Other Project Assets	546	2,016	1,633	2,473
	15,541	11,461	19,405	25,995
Administrative and other expenses				
Management fees and administration	3,843	3,105	7,943	5,484
Interest, net	2,518	10,553	5,312	20,170
Foreign exchange loss (gain)	4,224	12,929	2,432	9,506
Other income, net	(26)	(14)	(26)	(30)
Total administrative and other expenses	10,559	26,573	15,661	35,130
(Loss) income from operations before income taxes	4,982	(15,112)	3,744	(9,135)
Income tax expense (benefit)	3,618	(4,383)	8,491	(2,649)
Net (loss) income	1,364	(10,729)	(4,747)	(6,486)
Net loss attributable to noncontrolling interest	(81)		(129)	

Net income (loss) attributable to Atlantic Power Corporation shareholders	$	1,445	$	(10,729)	$	(4,618)	$	(6,486)

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 flow available for distribution was $7.5 million and $15.1 million for the three months ended June 30, 2010 and 2009, respectively and $25.3 million and $39.3 million for the six months ended June 30, 2010 and 2009, respectively. See "Cash Available for Distribution" on page 44 for additional information.

Income (loss) from operations before income taxes for the three months ended June 30, 2010 and 2009, was $5.0 million and $(15.1) million, respectively, and $3.7 million and $(9.1) million for the six months ended June 30, 2010 and June 30, 2009, respectively . See "Project Income" below for additional information.

Three months ended June 30, 2010 compared with three months ended June 30, 2009

Project Income

Auburndale Segment

The decrease in project income for our Auburndale segment of $0.2 million to $4.5 million in the three-month period ended June 30, 2010 from $4.7 million in the comparable 2009 period was not significant.

Lake Segment

Project income for our Lake segment increased $1.8 million to $6.7 million in the three-month period ended June 30, 2010 from $4.9 million in the comparable 2009 period. The increase is primarily attributable to the $2.1 million 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 the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" elsewhere in this MD&A for additional details about our derivative instruments and other financial instruments.

Pasco Segment

The increase in project income for our Pasco segment of $0.1 million to $0.3 million in the three-month period ended June 30, 2010 from $0.2 million in the comparable 2009 period was not significant.

Path 15 Segment

Project income for our Path 15 segment decreased $1.1 million to $1.9 million in the three-month period ended June 30, 2010 from $2.8 million in the comparable 2009 period. The decrease in project

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income at Path 15 is attributable to a non-recurring gain in prior year related to the settlement of disputes with landowners over right-of-way issues.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased $4.9 million to $1.7 million in the three-month period ended June 30, 2010 from a loss of $(3.2) million in the comparable 2009 period. The increase in project income at Chambers is primarily attributable to the non-recurrence of the planned major maintenance outage during the second quarter of 2009.

Other Project Assets Segment

Project income (loss) for our Other Project Assets segment decreased $1.5 million, to $0.5 million for the three months ended June 30, 2010 compared to a $2.0 million income in the comparable 2009 period. The most significant components of the change are as follows:

- increased expense at Selkirk in 2010 associated with the $1.9 million non-cash change in fair value of a natural gas contract that is recorded at fair value;

- the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's income expired in the fourth quarter 2009; partially offset by

- combined losses in the 2009 period of $1.7 million at the Mid-Georgia and Stockton projects, which were sold in fourth quarter of 2009.

Administrative and Other Expenses (Income)

Management fees and administration increased $0.7 million to $3.8 million for the three months ended June 30, 2010 from $3.1 million in the comparable period in 2009. The increase is primarily attributable to higher employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the second quarter of 2010 compared to the second quarter of 2009, resulting in higher expense in the 2010 period. In addition, we incurred expenses associated with our initial NYSE listing completed in July 2010.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense decreased $8.1 million to $2.5 million in 2010 from $10.6 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn$348 million principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

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 and, through 2009, our subordinated notes. 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). Foreign exchange loss decreased $8.7 million to a $4.2 million loss in 2010 compared to a $12.9 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate increased by 4.6% during the three months ended June 30, 2010. During the three months ended June 30, 2009, the rate decreased by 8.5%. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the three months ended June 30, 2010 compared to the foreign exchange loss (gain) in the comparable quarter of 2009.

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Six months ended June 30, 2010 compared with six months ended June 30, 2009

Project Income

Auburndale Segment

Project income (loss) for our Auburndale segment decreased $3.2 million to $4.2 million in the six-month period ended June 30, 2010 from $7.4 million in the comparable 2009 period. The decrease in project income for the six months ended June 30, 2010 is primarily attributable to the $4.8 million 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 the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our derivative instruments and other financial instruments. In addition, operations and maintenance costs were lower at Auburndale in the 2010 period due to timing.

Lake Segment

Project income for our Lake segment decreased $6.1 million to $3.9 million in the six-month period ended June 30, 2010 from $10.0 million in the comparable 2009 period. The decrease is primarily attributable to 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 the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our derivative instruments and other financial instruments.

Pasco Segment

Project income for our Pasco segment decreased $0.5 million to $0.9 million in the six-month period ended June 30, 2010 from $1.4 million in the comparable 2009 period. The decrease in project income at Pasco is attributable to the timing of operation and maintenance costs during the first quarter of 2009.

Path 15 Segment

Project income for our Path 15 segment decreased $0.6 million to $3.7 million in the six-month period ended June 30, 2010 from $4.3 million in the comparable 2009 period. The decrease in project income at Path 15 is attributable to a non-recurring gain in prior year related to the settlement of disputes with landowners over right-of-way issues.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased $4.7 million to $5.1 million in the six-month period ended June 30, 2010 from $0.4 million in the comparable 2009 period. The increase in project income at Chambers is primarily attributable to the non-recurrence of the planned major maintenance outage during the second quarter of 2009.

Other Project Assets Segment

Project income for our Other Project Assets segment decreased $0.9 million, to $1.6 million for the six months ended June 30, 2010 compared to a $2.5 million income in the comparable 2009 period. While the overall change in project income for the segment was not significant, the largest components of the change are as follows:

- the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's cash flow expired in the fourth quarter 2009; and

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combined losses in the 2009 period of $1.6 million at the Mid-Georgia and Stockton projects, which were sold in the fourth quarter of 2009.

Administrative and Other Expenses (Income)

Management fees and administration increased $2.4 million to $7.9 million for the six months ended June 30, 2010 from $5.5 million in the comparable period in 2009. The increase is primarily attributable to higher employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the first half of 2010 compared to the first half of 2009, resulting in higher expense in the 2010 period. In addition, we incurred expenses associated with our initial NYSE listing completed in July 2010 as well as in increase in business development costs during 2010.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense decreased $14.9 million to $5.3 million in 2010 from $20.2 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn$348 million principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

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 and, through 2009, our subordinated notes. 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). Foreign exchange loss decreased $7.1 million to a $2.4 million loss in 2010 compared to a $9.5 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate increased by 1.3% during the six months ended June 30, 2010. During the six months ended June 30, 2009, the rate decreased by 4.7%. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the six months ended June 30, 2010 compared to the foreign exchange loss (gain) in the comparable period of 2009.

Supplementary Financial Information

The key measure we use to evaluate the results of our projects is Cash Flow Available for Distribution. Cash Flow 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 Flow Available for Distribution is a relevant supplemental measure of our ability to pay dividends to our shareholders. A reconciliation of net cash provided by operating activities to Cash Flow Available for Distribution is set out below under "Cash Flow 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 Flow 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 less 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

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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 Flow 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.

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

	Three months ended June 30,		Six months ended June 30,	
(unaudited)	**2010**	**2009**	**2010**	**2009**
Project Adjusted EBITDA by individual segment				
Auburndale	$ 10,431	$ 10,386	$ 19,802	$ 18,547
Lake	7,299	7,723	14,612	15,621
Pasco	1,002	901	2,417	2,869
Path 15	7,062	6,931	14,115	13,833
Chambers	4,141	(1,128)	10,129	5,024
Total	29,935	24,813	61,075	55,894
Other Project Assets				
Mid-Georgia		628		1,386
Stockton		(1,259)		(1,114)
Badger Creek	774	512	1,510	1,732
Koma Kulshan	434	455	553	412
Orlando	1,870	2,136	3,671	3,975
Topsham	548	703	963	1,118
Delta Person	540	391	904	824
Gregory	1,428	1,113	2,283	2,271
Rumford	1	652	(7)	1,308
Selkirk	3,526	4,080	7,056	7,650
Other	(530)	(239)	(733)	(401)
Total adjusted EBITDA from Other Project Assets segment	8,591	9,172	16,200	19,161
Project income				
Total adjusted EBITDA from all Projects	38,526	33,985	77,275	75,055
Amortization	16,596	17,422	32,982	35,005
Interest expense, net	6,097	8,487	11,878	15,613
Change in the fair value of derivative instruments	210	(2,321)	12,729	(589)
Other (income) expense	82	(1,064)	281	(969)
Project income as reported in the statement of operations	$ 15,541	$ 11,461	$ 19,405	$ 25,995

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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 long-term 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						
Badger Creek	1,510		(7)		138	1,641
Delta Person	904	(1,023)	(137)		256	
Gregory	2,283	(823)	(112)	(39)	(443)	866
Koma Kulshan	553				(206)	347
Orlando	3,671		1	(66)	(1,706)	1,900
Rumford	(7)				7	
Selkirk	7,056	(4,657)	(1,181)	(309)	(909)	
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

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the six months ended June 30, 2009

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 18,547	$ (1,750)	$ (1,314)	$ (246)	$ (2,364)	$ 12,873
Chambers	5,024	(5,303)	(4,029)	(525)	4,833	
Lake	15,621		6	(426)	309	15,510
Pasco	2,869		43	(46)	4,084	6,950
Path 15	13,833	(3,801)	(6,444)		5,194	8,782
Total Reportable Segments	55,894	(10,854)	(11,738)	(1,243)	12,056	44,115
Other Project Assets						
Mid-Georgia	1,386	(816)	(1,734)		1,164	
Stockton	(1,114)		(35)	96	1,053	
Badger Creek	1,732		(2)		(130)	1,600
Delta Person	824	(541)	(190)		(93)	
Gregory	2,271	(2,132)	(221)	(46)	728	600
Koma Kulshan	412			(18)	(327)	67
Orlando	3,975		6	(189)	2,658	6,450
Rumford	1,308				(1,308)	
Selkirk	7,650	(4,247)	(1,586)	(59)	1,238	2,996
Topsham	1,118	(45)	(2)			1,071
Other	(401)		(111)	(46)	1,091	533
Total Other Project Assets Segment	19,161	(7,781)	(3,875)	(262)	6,074	13,317
Total all Segments	$ 75,055	$ (18,635)	$ (15,613)	$ (1,505)	$ 18,130	$ 57,432

Project Operations Performance Three months ended June 30, 2010 compared with three months ended June 30, 2009

Aggregate Project Adjusted EBITDA increased $4.5 million to $38.5 million in the three months ended June 30, 2010 from $34.0 million in 2009 and included the following factors:

- increased EBITDA at Chambers attributable to the non-recurrence of a planned major maintenance outage during second quarter 2009; and

- the absence of Stockton's second quarter 2009 loss resulting from higher maintenance costs from a forced outage in 2009. The Stockton project was sold in the fourth quarter of 2009.

Aggregate power generation for projects in operation at June 30, 2010 was 1.7% lower during the three-month period ended June 30, 2010 compared to the second quarter of 2009. Weighted average plant availability increased 4.0% over the period. Generation during the three months ended June 30, 2010 compared to the prior year period was unfavorably impacted primarily by reduced dispatch at the Selkirk project due to lower power prices and the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009, largely offset by increased generation at Chambers due to a scheduled outage in the second quarter of 2009 and increased generation at Lake associated with running during off-peak hours due to favorable market conditions.

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The project portfolio achieved a weighted average availability of 95.2% for the three-months ended June 30, 2010 compared to 91.2% in the 2009 period. The increase in portfolio availability in the second quarter of 2010 was primarily due to the planned outage at Chambers and an unplanned outage at Delta-Person in the second quarter 2009, slightly offset by a planned outage at Selkirk in the second quarter 2010. Each of the projects with reduced availability was nevertheless able to achieve substantially all of its 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, 2010 compared with six months ended June 30, 2009

Aggregate Project Adjusted EBITDA increased $2.2 million to $77.3 million in the six months ended June 30, 2010 from $75.1 million in the comparable 2009 period and included the following factors:

- increased EBITDA at Chambers attributable to the non-recurrence of a planned major maintenance outage during the six months ended June 30, 2009;
- increased EBITDA at Auburndale due to increased contractual capacity payments under the projects PPA;
- the absence of Stockton's loss during the first half of 2009 resulting from higher maintenance costs from a forced outage during 2009. The Stockton project was sold in the fourth quarter of 2009;
- the absence of EBITDA at Mid-Georgia as the project was sold in the fourth quarter of 2009;
- the absence of EBITDA at Rumford in 2010 as the contract that provided substantially all of the project's cash flow expired in the fourth quarter 2009; and
- decreased EBITDA at Lake attributable to higher fuel expense due to natural gas purchases at higher prices than those under the supply contract that expired in June 2009. We have a hedging strategy to mitigate its future exposure to changes in natural gas prices. See "Quantitative and Qualitative Disclosures About Market Risk" for additional information.

Aggregate power generation for projects in operation at June 30, 2010 was 6.6% lower during the six-month period ended June 30, 2010 compared to the first half of 2009. Weighted average plant availability increased 3.9% over the same period. Generation during the first six months of 2010 compared to the prior year period was unfavorably impacted primarily by reduced dispatch at the Chambers and Selkirk projects due to lower power prices and the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009, partially offset by increased generation at Lake due to favorable market conditions in the second quarter of 2009.

The project portfolio achieved a weighted average availability of 96.9% for the six-months ended June 30, 2010 compared to 93.0% in the 2009 period. The increase in portfolio availability in the first half of 2010 was primarily due to the planned outages at Gregory and Chambers in the second half of 2009. Each of the projects with reduced availability was nevertheless able to achieve substantially all of its 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 recontracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital

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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 $5.5 million for the six months ended June 30, 2010 over the comparable period in 2009. The change from the prior year is primarily attributable to a significant decrease in cash interest expense as a result of our common share conversion in December 2009, which eliminated Cdn$348 million of outstanding subordinated notes. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a $4.5 million decrease in distributions from our Orlando project and no distributions in 2010 from our Selkirk project, both of which are equity method investments. The decrease in distributions from Orlando was the result of a one-time receipt of insurance proceeds in 2009 related to an unplanned outage that occurred in 2008. The Selkirk project is currently not making distributions to partners as a result of restrictions in its non-recourse project-level debt. We expect to resume receiving distributions from Selkirk in 2011. An increase in corporate general administrative expenses of $2.5 million also reduced operating cash flow in the six months ended June 30, 2010 compared to the first half of 2009.

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 months ended June 30, 2010 were $1.9 million compared to $3.4 million for the six months ended June 30, 2009. We invested $3.0 million in Rollcast during the first quarter of 2009, compared to an additional $2.0 million investment in Rollcast during six months ended June 30, 2010. The cash consolidated in our balance sheet as a result of the additional investment in Rollcast was $2.5 million.

Cash Flow from Financing Activities

Cash used in financing activities for the six months ended June 30, 2010 resulted in a net outflow of $20.7 million compared to a net outflow of $21.5 million for the same period in 2009. Although the total cash used in financing activities did not change significantly in the six months ended June 30, 2010 compared to the same period in the prior year, the 2010 period included an increase in dividends paid of approximately $20 million. We completed our common share conversion in November 2009. As a result, Cdn$348 million of subordinated notes were extinguished and our entire monthly distribution to shareholders is now paid in the form of a dividend as opposed to the monthly distribution being split between a subordinated notes interest payment and a common share dividend during the six months ended June 30, 2009. This increase in dividends paid was offset by the proceeds of $20 million from a borrowing under our revolving credit facility that was used to partially fund our investment in Idaho Wind in July 2010.

Cash Available for Distribution

Prior to our conversion to a common share structure, holders of our IPSs received monthly cash distributions in the form of interest payments on subordinated notes and dividends on common shares. Subsequent to the conversion, holders of common shares receive the same monthly cash distributions of Cdn$1.094 per year in the form of a dividend on the new common shares. The payout ratio for the

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three and six month periods ended June 30, 2010 is significantly higher than our expected payout ratio for the full year 2010 of approximately 100%. Timing differences in operating cash flows and the purchases of property, plant and equipment are the primary contributors to these timing differences. For example, approximately $9 million of net cash tax refunds are expected in the second half of 2010 compared to approximately $1 million of net cash tax payments in the first half of the year. Also, our projects typically generate more operating cash flow in the second half of the year, particularly in the third quarter, due to the seasonality of electricity demand. In addition, purchases of property, plant and equipment for planned maintenance of our plants was higher in the first half of the year due to the advance procurement of capital property that will be installed in the fall, which is the typical time for planned maintenance due to lower electricity demand related to milder weather at that time of the year. From an overall cash flow perspective, we also expect to receive $2.5 million of proceeds from the sale of our interest in the Rumford project before the end of 2010 and approximately $3 million to $4 million in distributions of restricted cash from our projects as a result of more efficient management of project working capital. However, both the proceeds from Rumford and the restricted cash releases are classified as cash flows from investing activities in our consolidated statements of cash flows. Because only operating cash flows are included in the definition of cash available for distribution, these positive investing cash inflows will not be reflected as an increase in cash available for distribution or as a benefit to the presentation of the payout ratio. Cash Available for Distribution decreased by $7.6 million for the three months ended June 30, 2010 from the 2009 period and decreased by $13.9 million for the six months ended June 30, 2010 from the 2009 period as set forth in the following table:

(unaudited)	**Three months ended June 30,**		**Six months ended June 30,**	
(in thousands of U.S. dollars, except as otherwise stated)	**2010**	**2009**	**2010**	**2009**
Cash flows from operating activities[1]	15,139	12,171	35,978	30,524
Project-level debt repayments	(6,441)	(5,108)	(9,141)	(6,414)
Interest on IPS portion of subordinated notes[2]		8,365		16,078
Purchases of property, plant and equipment	(1,201)	(311)	(1,520)	(933)
Cash Available for Distribution[3]	7,497	15,117	25,317	39,255
Interest on subordinated notes		8,365		16,078
Dividends on common shares	15,913	6,079	31,714	11,672
Total distributions to shareholders	15,913	14,444	31,714	27,750
Payout ratio	212%	96%	125%	71%
Expressed in Cdn$				
Cash Available for Distribution	7,710	17,642	26,187	47,320
Total distributions to shareholders	16,556	16,561	33,083	33,234

(1) Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows has been reported as an investing activity to reflect the use of the restricted cash in the current period. In previous periods, changes in restricted cash were reported as cash flow from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

(2) Prior to the common share conversion in November 2009, a portion of our monthly distribution to IPS holders was paid in the form of interest on the subordinated notes comprising a part of the

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IPSs. Subsequent to the conversion, the entire monthly cash distribution is paid in the form of a dividend on our common shares

(3) Cash Flow 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 Financial Information".

Outlook

Based on year-to-date results and our projections for the remainder of the year, we expect to receive distributions from our projects in the range of $75 million to $80 million for the full year 2010, an increase from our previous guidance of $70 million to $77 million. This amount represents a decrease of approximately $20 million to $25 million compared to distributions received from the projects in 2009. The 2010 reductions in project distributions have historically been included in our long-term cash flow projections when we periodically confirm our ability to continue paying dividends to shareholders at current levels. Additional details about these changes are included below.

At the corporate-level, we expect a net cash tax refund in 2010 in the range of $7 million to $9 million, compared to insignificant net cash taxes in 2009. Included in 2010 corporate-level costs will be the $5 million payment under the terms of the management agreement termination, down from the $6 million payment in 2009.

Looking ahead to 2011, we expect overall levels of cash flow to be improved over projected 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and a slightly lower payment under the management agreement termination are expected to be partially offset by the non-recurrence of the cash tax refunds that are anticipated in 2010. In 2012, still higher 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 one-time items and contract expirations comprise the most significant of the decreases in projected 2010 project distributions compared to 2009.

- Final insurance proceeds received in 2009 at Orlando due to the unplanned outage in early 2008.
- Increase in debt principal payments in 2010 for Auburndale project level debt.
- Resolution in 2009 of the landowner litigation over right-of-way issues at Path 15, which resulted in $6 million being released from the construction reserve account.
- Final payment related to Pasco's prior PPA that expired at the end of 2008 which was received in early 2009.

In 2009, the following five projects comprised approximately 86% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2010, we expect these same five projects to contribute approximately 90% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2010 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 the expiration of its PPA in July, 2013. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively

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fix the forward price of natural gas required at the project. We have taken advantage of the low market price of natural gas to make significant progress in our natural gas hedging strategy. These hedges are summarized below under "Quantitative and Qualitative Disclosures About Market Risk". We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2011 and 2013, but do not intend to execute additional hedges at Lake for 2010 or 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 electricity 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 $27 million to $29 million in 2010. In 2011 and 2012, expected distributions from Lake are expected to be $30 million to $34 million per year. The increases in 2011 and 2012 are primarily due to higher contractual capacity and energy revenue and lower natural gas prices than in 2010.

Auburndale

Based on the current forecast, we expect distributions from Auburndale of $25 million to $27 million per year from 2010 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2010 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 coal costs 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 throughout the PPA's expiration in mid-2012. 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. See "Quantitative and Qualitative Disclosures About Market Risk" for additional details about hedge contracts executed as of August 9, 2010. The 2010 and 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 the 2012 to 2013 period.

Chambers

As expected, we reported a significant decrease in cash flow at the Chambers project in 2009 due to a planned major maintenance outage during the year, changes in market power prices and expected sales volumes and the expense associated with regional carbon allowance purchases.

As previously reported, the reduced cash flows resulted in the project not meeting cash flow coverage ratio tests in its non-recourse debt, so we received no distributions from Chambers in 2009 and do not expect to receive distributions from Chambers in 2010. Based on our current projections, we will resume receiving distributions from the project in 2011 based on meeting the required debt service coverage ratios.

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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.

We do not expect any material unusual requirements for cash outflows in 2010 for capital expenditures or other required investments. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2010. See "Outlook" above for information about changes in expected distributions from our projects in 2010.

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 1.50% and 3.25% that varies based on the credit statistics of one of our subsidiaries. As of June 30, 2010, the applicable margin was 1.50%. As of June 30, 2010, $39.4 million was allocated, but not drawn, to support letters of credit for contractual credit support at seven of our projects. In June 2010, we borrowed $20 million under the credit facility and used the proceeds to partially fund the acquisition of IWP in July 2010.

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 the bank. 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

On October 11, 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, for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures initially had a maturity date of October 31, 2011 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. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014.

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible debentures, which we refer to as the 2009 Debentures, for gross proceeds of $71.4 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009

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Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share.

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, 2010 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, 2010, the covenants at the Chambers, Selkirk and Delta-Person projects are temporarily preventing those projects from making cash distributions to us. We expect these projects to resume cash distributions in 2011. All project-level debt is non-recourse to us and substantially all of the principal is amortized over the life of the projects' PPAs. The non-recourse holding company ("holdco") debt to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. From January 1 to July 31, 2010, we have contributed approximately $2.7 million to Epsilon Power Partners for debt service payments on the holdco debt. We expect to make further contributions to Epsilon Power Partners ranging from $0.3 million to $0.9 million during the remainder of 2010 before it is expected to begin receiving distributions from Chambers in amounts that are adequate for servicing the holdco debt.

The range of interest rates presented represents the rates in effect at June 30, 2010. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2010	2011	2012	2013	2014	Thereafter
Consolidated Projects:								
Epsilon Power Partners	8.40%	$ 36,982	$ 500	$ 1,500	$ 1,500	$ 3,000	$ 5,000	$ 25,482
Path 15	7.9% - 9.0%	157,608	3,740	7,987	8,667	9,402	8,065	119,747
Auburndale	5.10%	26,600	4,900	9,800	7,000	4,900		
Total Consolidated Projects		221,190	9,140	19,287	17,167	17,302	13,065	145,229
Equity Method Projects:								
Chambers	0.4% - 7.2%	80,571	5,526	11,294	12,176	10,783	5,780	35,012
Delta-Person	2.3%	11,059	124	1,220	1,308	1,403	1,505	5,499
Selkirk	9.0%	20,999	4,206	10,948	5,845			
Gregory	2.1% - 7.5%	15,217	934	1,901	2,044	2,205	2,385	5,748
Total Equity Method Projects		127,846	10,790	25,363	21,373	14,391	9,670	46,259
Total Project Level Debt		$ 349,036	$ 19,930	$ 44,650	$ 38,540	$ 31,693	$ 22,735	$ 191,488

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, 2010, restricted cash at the consolidated projects totaled $14.6 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 2010, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is reduced from 2009. In the second quarter, Selkirk completed a minor inspection of one of its combustion turbines, with costs and lost margin largely covered by reserves and gas resales proceeds, respectively. Selkirk's planned major overhaul of a steam turbine has been postponed to 2011 due to maintaining a high steam quality. At Orlando, a minor gas turbine inspection was completed in May. Auburndale is scheduled to conduct a minor inspection of one of the facility's combustion turbines, which is covered by its long-term service agreement, in conjunction with other maintenance work. Chambers completed its scheduled outage to inspect and complete customary repairs on one boiler. Due to the facility's low dispatch, the planned outage of its other boiler has been postponed to 2011.

Off-Balance Sheet Arrangements

As of June 30, 2010, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. The combination of long-term energy sales and fuel purchase agreements are 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 from the expiration of its natural gas supply contract on June 30, 2009 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 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.

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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 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.

For the remainder of 2010, projected cash distributions at Auburndale would change by approximately $0.3 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 2010, projected cash distributions at Lake would change by approximately $0.5 million per $1.00/Mmbtu change in the price of natural gas based on the current level of unhedged 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.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of August 9, 2010:

	2010	2011	2012	2013
Portion of gas volumes currently hedged:				
Lake:				
Contracted				
Financially hedged	80%	78%	90%	65%
Total	80%	78%	90%	65%
Auburndale:				
Contracted	80%	80%	40%	
Financially hedged	15%	13%	32%	79%
Total	95%	93%	72%	79%